Development of Strategies for Deployment of Biomass Resources in the Production of Biomass Power

Final Report

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Overview

The study analyzes strategies for deployment of biomass resources for Biopower generation. It evaluates and compares several biomass supply databases. It also compares the projected biopower market penetration for several alternative incentive scenarios. It analyzes the availability of biomass to meet the projected market demands. Based on the analysis, a summary of findings and recommended future research is presented.

Biopower, the production of electricity from biomass, is one of the most promising alternatives to the production of electricity from fossil fuels. According to the Energy Information Administration (EIA) Energy Outlook 2002, of the renewable energy resources under development, wind and biomass have the greatest potential to penetrate the electric market in the next twenty years. Although a variety of programs and incentives have been deployed in the past, the market for new biopower has been limited. A key reason for the lack of biopower growth has been the limited availability of biomass at a price competitive with coal.

Many studies have been undertaken to assess the impact of alternative policy scenarios on biopower potential. In this study several of the projections made in the last two years were selected for evaluation: the Energy Information Administration (EIA), Oak Ridge National Laboratory (ORNL), OnLocation Inc., and ICF Inc. Three models were used in these projections: the National Energy Modeling System (NEMS), the Oak Ridge Competitive Electricity Dispatch (ORCED) model, and the Integrated Planning Model (IPM). The projections included several national projections and the ORNL Southeast Study projections. Projections were made for four scenarios: Base or Reference Case, Unlimited Resources, Renewable Portfolio Standards (RPS), and Environmental Impact Standards. Several options were projected under each scenario. In total, projections were made for over 27 options.

The study compared and evaluated the basic assumptions, the inputs to the projections, and the projection results. For each scenario the study a) compared market penetration among the models, b) evaluated the reason for variation of results between the models, c) compared the results and identified the variation of results in the different regions, and d) analyzed the market potential and the impact on the prices that power plants would pay for biomass under the alternative projections.

The economic viability of biopower is dependent in part on the cost and availability of biomass. Biomass prices for biopower vary by the type of biomass and by the distance of the biomass from the power plant. There are two major biomass categories: biomass residues and energy crops. Four types of biomass residues are used as fuel for generating electricity including, agricultural residues, forest residues, mill residues and urban wood waste. Energy crops are plants that are grown solely for the use of energy production. The energy crops are divided into two types: grasses and short rotation woody (SRW) crops. The quantities of available biomass were estimated by the biomass type and price. Three biomass supply databases were reviewed, one developed by NEMS and two developed by ORNL.

Biopower's potential market is dependent in part on the availability of biomass at a price competitive with coal. Each projection was evaluated to determine a) the quantities of resources needed to meet the demand, b) the competitive price that power plants could pay for biomass, c) the availability of adequate resources to meet the demand at the competitive price, d) the types of resources that were available to meet the biomass demand, e) the resource price that would ensure the availability of adequate resources to meet the demand.

The availability of resources, the type of resources, and the price of resources that would be required to meet the projected markets were determined for each alternative policy.

The report is divided into six chapters. Chapter One presents a summary of findings and recommendations for future research. Chapter Two describes the models used in the projections. Chapter Three describes and compares the results of the national projections. Chapter Four describes and compares the biomass resource databases used in the projections. Chapter Five analyzes the national projections with resource availability. In Chapter Six the Southeast Regional Study projections are analyzed.

Contributions

The report is based on studies, publications, databases, discussions, and input from several agencies and individuals. Thanks and gratitude are extended to the following:

Lynn Wright, Marie Walsh, Bob Perlack, Stan Hadley, Jim Van Dyke and Shahab Sokhansani - ORNL
Zia Hag – EIA
Juanita Haydel and Thapa Bishal - ICF
Frances Wood – OnLocation
Larry Goldstein – NREL
Kevin Comer and Edward Gray – Antares

Selected memos or reports prepared by the individuals are included in the appendices. There will not be specific credit notations in the body of the report. Reports from which information was used in the study are:

Biomass for Electricity Generation, http://www.eia.doe.gov/oiaf/analysispaper/index.html Zia Hag, EIA, DOE

Annual Energy Outlook 2002 http://www.eia.doe.gov/oiaf/aeo/index.html

ICF Memorandum: Potential Market Penetration of Biomass Co-firing, Interim Report - January 31, 2001

ICF Memorandum: Results of Phase II of Study on Potential Market Penetration of Biomass Co-firing – July 19, 2001

NREL Memorandum: Biomass Co-firing Use at $20/Dry Ton. S. W. Hadley, 11/10/2000

NREL Memorandum: Biomass Co-firing Use at $20/Dry Ton with 15% Maximum. S. W. Hadley, 2/23/2001

Alternative Biomass Co-firing Scenarios Using NEMS, Prepared by OnLocation Inc., for the National Renewable Energy Laboratory, December 2000.

Data received from Marie Walsh and Bob Perlock on ORNL Supply Curves and the Southeast Study and Zia Hag, EIA on NEMS Supply Curves and the RPS Projections

Evaluation of Analysis Needs (Modeling and Data) for the BioPower Program, Prepared for Oak Ridge National Laboratory by the Antares Group, Incorporated, August 2001

Engineering Aspects of Collecting Corn Stover for Bioenergy, Shahab Sokhansanj, Anthony Turhollow, Janet Cushman, John Cundiff, Oak Ridge National Laboratory, 2001

Baseline Cost for Corn Stover Collection, Shahab Sokhansanj and Anthony Turhollow, Oak Ridge National Laboratory, May 2001

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Summary of Findings and Recommended Research

Summary of Findings

Incentives

A combination of incentives that include Renewable Portfolio Standards (RPS) for biopower, Environmental Impact Standards (EIS) for the electric generation industry, and agriculture policies that encourage the use of biomass from CRP land would insure the competitiveness of biopower in the market place. The incentives need to be high enough to enable power producers to pay at least twice the current competitive price with coal for biomass. If the incentive would allow the price for biomass to be twice the current biomass competitive price of coal, the market potential will double over the Reference Case, in which no incentive is applied. If the incentives would allow power plants to pay triple the competitive price of coal for biomass, the market would quadruple, and if the price were four times the competitive price of coal, the market would increase ten-fold.

The Renewable Portfolio Standards options tested are large enough to make an impact on biopower market penetration. If the standards are mandated there will be more than adequate resources to meet the demand. Under the RPS requirements, the biomass value is equivalent to more than three times the current competitive biomass price of $20/ton.

The combined value of the two incentives, if applied only to the biomass price, would enable utilities to pay as much as four times the current competitive price of coal.
Based on the three-cent penalty assumed by the RPS projections, the incentive value of the RPS is $46-$50/ton. Based on the Southeast Study model calculation of the maximum price paid for resources, the Low Carbon option incentive value is $18-$29/ton and the High Carbon value is $29-$30/ton.

Most of the market for biopower is concentrated in the Southeast (SERC/STV) and Mid-Atlantic (ECAR and MAIN) regions. Most projections predict that these three regions would account for 50%-70% of the 2020 biopower market.

The chart below shows the total projected biomass used under the Renewable Portfolio Standards and the Environmental Impact Standards scenarios, for the year 2010.

Table 1. Comparison of NEMS and Southeast Study Projections for the Southeast Region		
Projections	Million Dry Ton	Trillion Btu
Southeast Study Base Case	0.6	10
RPS Reference Case 2010	2.2	38
RPS Reference Case 2020	1.3	21
Southeast Study High Carbon, 2% co-firing	3.6	60
Southeast Study Low Carbon, 2% co-firing	3.7	63
10% RPS, 5% co-firing, 2010	4.5	77
10% RPS, 5% co-firing, 2020	13.6	231
20% RPS, 5% co-firing, 2010	14.1	240
20% RPS, 5% co-firing, 2020	18.0	306
Southeast Study Low Carbon, 15% co-firing	23.9	407
Southeast Study High Carbon, 15% co-firing	27.5	468

The two incentives combined could provide a large market for biomass. If the Southeast Study Low Carbon projection is adjusted to correspond to 5% co-firing and combined with the 10% RPS projection for 2020, the Southeast biopower market would need about 23 million tons of biomass. Twenty-two percent of the total 102 million tons of biomass estimated by the Southeast Study would be used. Forty-five percent of the NEMS biomass estimate for the region would be used.

An incentive package that would mandate a 10% Renewable Portfolio Standard and a Low Carbon Environmental Impact Standard could result in a national biopower market that would use 1,100- 1,500 trillion Btu (65-88 million tons) in the year 2020, utilizing 15% to 21% of the NEMS-estimated 7100 Trillion Btu (418 million tons) annual biomass in 2020 estimated.

Resource Availability to Meet Projected Demand

If Renewable Portfolio Standards and Environmental Impact Standards were enacted, market penetration could be limited by the availability of resources. Incentives that would allow power producers to pay less than $40/dry ton will not have a significant impact on biopower market penetration because there aren't enough biomass resources at prices below $40/dry ton.

All of the available resources, estimated by NEMS supply curves, at $20/dry ton are from urban wood waste. The availability of these resources is questionable for several reasons: a) a very low cost was assumed for processing, b) communities in urban areas oppose the use of biomass for biopower because of traffic, noise and aesthetics, c) the spatial location of the resources relative to the location of power plants limits the resources to a small number of plants in any given region, and d) the cost and availability of land for biomass storage for power plants in urban areas is a limiting factor.

The NEMS resource estimates at $30/dry ton are comprised of 75% urban wood waste and 25% forest residues. The quantities are also overestimated at this price for the same reasons listed in the previous paragraph.

At $40/dry ton, the resource availability is comprised of 43% agriculture residues and 30% forest residues. The Southeast Study suggests that the availability of agriculture residues in the NEMS supply curves may be overestimated. The Southeast Study estimates for agriculture residues in the SERC/STV are 95% lower than the ORNL national supply curve estimates.

There are adequate quantities of biomass at $50/dry ton to meet most projections.

At $40-$50/ton, energy crops become a major contributor to the supply mix. Based on the ORNL supply curve estimates, energy crops would provide 37% of the total estimated resources in 2008. Based on the Southeast Study, the quantities of switchgrass would be much higher than the NEMS estimate at prices of $40/ton. The biomass estimated by the Southeast Study is two and half times the NEMS supply curve estimates for the SERC/STV region. <u>Switchgrass would be a critical resource for biopower market expansion</u>.

Table 2. Comparison of Projected Resource Used and Resource availability for Alternative Scenarios -Trillion Btu

	2010					
Co-firing Rate	**5%**			**10-15%**		
Projected Option	Resource Used	Resource Available	Percent of Available	Resource Used	Resource Available	Percent of Available
ORNL-Unlimited Resources	719	6586	11%	2170	6586	33%
OnLocation-Unlimited Resources	847	6586	13%	2432	6586	37%
ICF-Unlimited Resources	225	6586	4%	778	6586	12%
ICF - Tripling the Market-Reference				300*	6586	5%
EIA - RPS Reference	248	6586	4%			
EIA - RPS 10%	435	6586	7%			
EIA - RPS 20%	1182	6586	18%			
ICF - Tripling the Market				700*	6586	11%
	2020					
ICF - Unlimited Resources	217	7100	3%	657	7100	9%
ICF - Tripling Market-Reference				300*	7100	4%
EIA - RPS Reference	191	7100	3%			
EIA - RPS 10%	1162	7100	16%			
EIA - RPS 20%	1492	7100	21%			
ICF - Tripling the Market				700*	7100	10%

* 10% Co-firing

If the Southeast Study biomass estimates are applicable nationwide, more resources would be available at $40/ton and the level of incentives could be lower. A lower level of incentives would have a smaller impact on the added kWh price to the customer.

The Unlimited Resources projections do not include any processing cost. Although there is projected biopower market increase at the price of $20/ton, if the processing cost would be included, biomass at $20/ton would not be competitive with coal. Assuming processing cost of at least \$5-\$10/ton, the biomass price competitive with coal would be \$10-\$15/ton. If the heat loss and operation and management cost is added, the competitive price with coal, without incentives, at the power plant gate, is even lower.

If utilities could pay \$20-\$30/ton for biomass, biopower market expansion would be limited to co-firing in regions where coal prices are high and SO_2 mitigation is at premium.

Biomass Supply Estimates

The cost of processing, which includes cleaning, drying, grinding, densification, loading and moving, and storage, is either underestimated or not included at all in the biomass supply curves. If the complete cost of processing were included in the supply curves, biomass quantities at the lower price range of \$20-\$40/dry ton would decrease substantially.

The projections assume that all of the estimated biomass resources are available exclusively for biopower use. If biofuels had similar incentives, and or industry had an increased demand for biomass products, the resource availability for biopower would be smaller and the market penetration, at the lower biomass price categories, would be smaller.

Because of the uncertainty, in terms of cost and availability, of both agriculture residues and forest residues, the future for biopower without energy crops would be limited.

To have biomass for biopower, utilities would have to pay about \$50/ton. Since each region has a different predominant residue type, at \$50/ton, the combination of at least one residue type with an energy crop would be needed to insure availability of reliable biomass resources to all plants in that region.

Each region has a different combination of resource types. The level of competition for resources among users depends on the resource composition and the type of resources each user would require. For example, if agriculture residues and switchgrass were the main resources used by biofuels and biopower, there would be competition for these resources in the ECAR and MAIN regions. In these regions there may not be adequate resources to meet the demand for both.

The majority of resources at $40/ton are from agriculture residues. There is a debate as to the quantities of agriculture residues that could be removed from the field. A simple calculation suggests that if the farmer's income is $10/ton, the cost of collection is $20/ ton (based on Shahab Sokhansani estimates), the transportation cost to the plant is $10/ ton, and the processing and storage cost at the plant is $5/ ton, the total cost would average $45/ ton.

Models Capability

The NEMS and ORCED models provide complementary capabilities to project the market potential for biopower. A major deficiency of the NEMS model is the assumption that total resources in a region are available to all power plants in that region and transportation costs are fixed at $10/ton. A deficiency of ORCED model is that it does not have algorithms to predict changes over time and only provides a snap shot of a given time. The ORCED model, in combination with other ORNL models, can project the biopower market based on the availability of resources for each individual plant and calculate the transportation cost for each plant based on the resource distance from the plant. The two models could be used together or in sequence. The NEMS model would be used to project the future number and location of power plants for any region for any given year. The output would than be used by the ORCED model to project and compare with the NEMS results, the potential for any given region.

Recommendations for Future Research

Biopower market projection assuming both the RPS and the Low Carbon standards. A biopower market projection using the three models, NEMS, ORCED and IPM, under identical assumptions, that would include the two incentives, 10% RPS and a Low Carbon standards, is recommended to estimate the probable biopower market potential. The recommended projections with the IPM model would be useful for comparison with NEMS projections and for dialogue and communication between DOE and EPA.

Economic analysis of alternative sets of incentives. The study was limited to the analysis of the projected biopower potential and biomass availability for selected scenarios. It did not include an economic analysis. The economic impact of different combinations of RPS, EIS, and CRP policies and incentives should be analyzed. The economic analysis should be comprehensive and include an assessment of the impact on consumer electric prices, the environmental benefits, and the economic impact on the rural economy. The results of such a study would help draft an incentive program and provide background that could explain the reasoning for any recommended incentive package for biopower.

Processing and transport infrastructure systems. All the models assume that processing, or converting the raw wood to a form appropriate for firing, is done at the power plant site. It would be more economical and efficient for utilities to purchase biomass in a form ready to be fed into the boiler and not be involved in the processing of biomass. Concepts of resource collection, processing, and distribution systems between the farm or resources collection gate and the power plant should be explored and evaluated. For example, a system in which a multi-purpose processing center could be located along railroad tracks, where the railroad would be used for biomass transport. The centers would collect all the waste wood in the area, prepare the biomass in according to each user needs, and deliver the end product to the site. The centers would provide biomass to all users including biopower, biofuels, and industrial production plants. Such a system has the potential to increase the efficiency of the processing and delivery system. It would eliminate the utilities' need to invest in biopower processing equipment and purchase or use valuable space for processing and storage.

Energy crops research If policies were enacted to increase the biopower market, the level of market penetration would depend, to a large extent, on the availability of switchgrass and other energy crops. Extensive research to improve the yield and efficiency of switchgrass, particularly on CRP land, is recommended. In the Northern regions, the cost of willows and poplars are similar to switchgrass. In the Southeast, willows and poplars are twice as expensive as switchgrass. SRWC that would be more cost competitive in the Mid-Atlantic and the Southeast region, where a high percentage of market penetration is projected, should be a priority for the SRWC research.

Supply curves update. The basic data used to develop the NEMS biomass supply curves, which is being used by most agencies conducting biopower research, is over 15 years old. Agencies using the NEMS supply curves have different versions of the database. New estimates are needed that would calculate the resources in today's dollars rather than 1987 dollars. The Southeast Study estimates also reinforce the need to develop new supply curves. The supply curves should be estimated for small geographic areas. They also should include higher price categories. The highest price for which ORNL data estimate the availability of biomass is $50/dry ton at the farm gate. Considering the biomass equivalent value of the combined incentives of Renewable Portfolio Standards and Environmental Impact Standards, the maximum price for which biomass is estimated at the farm gate should be increased to at least $60/ton.

Processing cost. A full accounting of the biomass processing cost to the mouth of the boiler is needed. The study should calculate the full processing cost for cleaning, drying, grinding, densification, storage, and local transport, *for each resource type and for the biomass form required by each boiler type*. The information, which would better reflect the price of biomass, should be used in future biopower market projections.

Conduct simultaneous projection for biofuels, biopower and industry. The projections for the biopower market potential, assuming biopower has unlimited access and use of all available biomass, is unrealistic. Demand projections for biomass should be conducted simultaneously for biopower, biofuels and industry. Such projections should include an analysis of the desirable resource type for each user and the economic price that each would pay under alternative incentive scenarios.

Regional projections for regions with high biopower potential The national projections assume that the total quantity of biomass in a given region is available to all power plants in that region. The regions are very large and include multiple States. The method distorts the true availability of resources for each plant. The NEMS supply curves include a flat $10/ton for transportation. The Southeast Study assumes a transport system by rail to each power plant and calculates the cost and availability of resources based on the location of the resource and the road network to the plant. The cost of transportation to a plant will vary by the resource distance to the power plant and the method of transport, i.e. rail or truck. The Southeast Study more accurately reflects the biopower potential and the resource availability of each plant. Additional studies for regions with high potential are recommended. The studies would help in the analysis of resource issues in each of these regions.

Analysis to ascertain the reason for the differences between the IPM model projections and the NEMS projections. The IPM projections were lower compared with the other models. Although it was speculated that the reason for the smaller market was due to the IPM model using the supply curves instead of the Unlimited Resources scenario, the reason for the difference should be further explored. The analysis is recommended because EPA is using the ICF-IPM model in their analyses to establish environmental policy. The study should investigate the input and output of the two models and identify the reasons for the differences in the projections.

Case projects to analyze the cost and availability of forest residue and agriculture residues
The two resources account for the 62% of the total biomass. Agriculture residues are the largest resource followed by forest residues. In some regions, agriculture residues are the dominant resource; in others forest residues are the largest resource. Since there is a debate as to how much residue can be collected and at what cost, it is recommended that the economics of collecting agriculture and forest residues be evaluated through case studies. Incentive policies that would enable the use of forest residues on public land and agriculture policies for the use of CRP land should also be explored. Efficient collection techniques should be researched.

Processing technologies. Development of technologies to automate the processing system, including technologies for cleaning, drying, chipping, densification, and storage are needed. The technology development could be researched in combination with the development of options for the processing and transport infrastructure.

Models

Three models were used in projecting the more than 27 options under four alternative scenarios by the four agencies whose projections were included in the study. The three models are: the National Energy Modeling System (NEMS), the Integrated Resource Planning Model (IPM), and the Oak Ridge Competitive Electricity Dispatch (ORCED). The Energy Information Administration (EIA) and OnLocation Inc., under contract with the National Renewable Energy Laboratory (NREL), used the NEMS model. ICF used the IPM model in their projections for ORNL and the Environmental Protection Administration (EPA) and ORNL used the ORCED model.

Model Descriptions

The model descriptions below are from material prepared and published by each of the organizations that developed the models.

<u>ICF - Integrated Planning Model (IPM)</u>

IPM is a multi-region linear programming model that determines the least-cost operation of the electric power system to meet a specified electricity demand. IPM decides upon the operation of the existing system and chooses new units and retrofit options based on the criteria of meeting demand at least-cost subject to constraints imposed. Constraints include unit operating constraints, emissions caps, interregional transmission limits, and regional reserve margins, among others. The model draws on a database containing detailed information on the characteristics of each utility boiler and generating unit in the U.S. For modeling purposes, these units are aggregated into *model plants* of similar characteristics. The model has a comprehensive retrofit structure that allows modifications to existing units (environmental and other) based on economics. IPM structurally models biomass co-firing by substituting the allowed percentage of coal fuel (on a Btu basis) with biomass fuel. In IPM, plants select biomass co-firing only if it is economically more attractive than the other options.

IPM projects capacity expansion and dispatch for generations into the future by selecting options that will meet electric demand at least cost to the overall power system. Ordinarily this will simply mean dispatching those existing units that have the least variable costs and building new units or retrofitting existing units in the way that will yield the lowest cost to meet growing electricity demand. If the scenario includes an environmental constraint, then the model considers retrofit, new construction, or fuel switching options that will not only meet electricity demand but also stay within emissions limits prescribed by the environmental constraint.

ORNL - Oak Ridge Competitive Electricity Dispatch (ORCED)

ORCED is a program for analyzing the electricity supply system for a given region or utility system based on power generating plant information and the region's hourly electric load demands. ORCED uses the plant dispatch information, fuel costs, and the region's power demands to calculate air emissions, electricity costs and prices, and other operational factors of a regional electricity market. Power plant and demand data are provided on this site for the ten reliability regions of the North American Electric Reliability Council or NERC so that users can download and begin analyses relatively quickly and easily.

IEA - National Energy Modeling System (NEMS)

NEMS represents the behavior of energy markets and their interactions with the U.S. economy. The model achieves a supply/demand balance in the end-use demand regions, defined as the nine Census divisions, by solving for the prices of each energy product that will balance supply and demand. The system reflects market economics, industry structure, and energy policies and regulations that influence market behavior. The three economic growth cases in EIA's AEO2001 are based on macroeconomic forecasts prepared by Standard & Poor's DRI.

The NEMS model is built around a central integrating module that controls the execution of 12 component modules. There are four supply modules: oil and gas, natural gas transmission and distribution, coal market, and renewable fuels. There are two conversion modules – one for the electricity market and one for the petroleum market. There are four end-use demand modules: residential, commercial, transportation, and industrial. Additionally, there is an international energy module (simulates world oil markets) and a macroeconomic module. The integrating module calls each supply, conversion, and end-use demand module in sequence until supply and demand equilibrium has occurred (other variables are also evaluated for convergence, such as petroleum product imports, crude oil imports, and macroeconomic indicators). This convergence algorithm is repeated for each year of projection (currently through 2020). Each module of NEMS embodies many assumptions and data to characterize the future production, conversion, or consumption of energy in the United States.

Two major assumptions concern economic growth in the United States and world oil prices, as determined by world oil supply and demand. The reference case uses the mid-range assumptions for both the economic growth rate and the world oil price. Other cases include potential legislative and regulatory changes, such as competitive pricing of electricity, Renewable Portfolio Standards, gasoline standards, and equipment standards; changes in nuclear retirement assumptions; a sensitivity on electricity demand growth; changes to oil and gas technology; and changes to coal supply productivity and miner wages. Some of these cases exploit the modular structure of NEMS by running only a portion of the entire modeling system in order to focus on the first-order impacts of the changes in the assumptions.

Comparison of Regions Used by the Models

The models prediction is by multi-State regions. There are differences in the number of regions used by the models. NEMS and ORCED used the North American Electric

Reliability Council (NERC) system. The ORCED prediction is for ten regions the NEMS is for 13 regions. IPM projections are by the 21 Electric Power Market Regions. The IPM regions correspond in most cases to the regions and sub-regions used by the North American Electric Reliability Council (NERC). The difference between the regions used by the three models is the level of breakdown of the ten regions used by ORCED. ORCED's single region in the west is divided into three regions and ORCED's single region in the Northeast is divided into two regions. IPM's twenty-one regions are the next level of subdivision of the thirteen major NERC regions. Since IPM smaller regions are in most cases divisions of the larger regions, the smaller regions data could be compiled into the ten regions, used by ORCED, when comparing the results among the models. The thirteen NERC regions used by NEMS, and the States for each, are:

1) ECAR, East Central Area Reliability Coordination Agreement; Pennsylvania (0.157), West Virginia, Indiana, Michigan, Ohio, Virginia (0.6), Kentucky (0.844)
2) ERCOT, Electric Reliability Council of Texas; Texas (0.819)
3) MAAC, Mid-Atlantic Area Council; Delaware, Maryland (0.86), New Jersey, Pennsylvania (0.772)
4) MAIN, Mid-America Interconnected Network; Illinois (0.985), Missouri (0.319), Wisconsin (0.607)
5) MAPP, Mid-Continent Area Power Pool; Illinois (0.015), Iowa, Minnesota, Nebraska, North Dakota, South Dakota (0.926), Wisconsin (0.393), Montana (0.159)
6) NPCC/NY, Northeast Power Coordinating Council/New York; New York, Pennsylvania (0.071)
7) NPCC/NE, Northeast Power Coordinating Council/New England; Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont
8) SERC/FL, Southeastern Electric Reliability Council/Florida
9) SERC/STV, Southeastern Electric Reliability Council (Excluding Florida); Georgia, North Carolina, South Carolina, Virginia (0.6), Alabama, Kentucky (0.156), Mississippi (0.533), Tennessee
10) SPP, Southwest Power Pool; Kansas, Missouri (0.681), Arkansas, Louisiana, Mississippi (0.467), Oklahoma, Texas (0.16), New Mexico (0.71)
11) WSCC/NWP, Northwest Power Pool; Idaho, Montana (0.841), Nevada, Utah, Wyoming (0.4), Oregon, Washington
12) WSCC/WRA, Rocky Mountain Power Area; South Dakota (0.074), Texas (0.819), Arizona, Colorado (0.996), New Mexico (0.71), Wyoming (0.6)
13) WSCC/CNV, California and Southern Nevada Power

Figure 1: U.S. portion of North American Electric Reliability Council (NERC) regions.

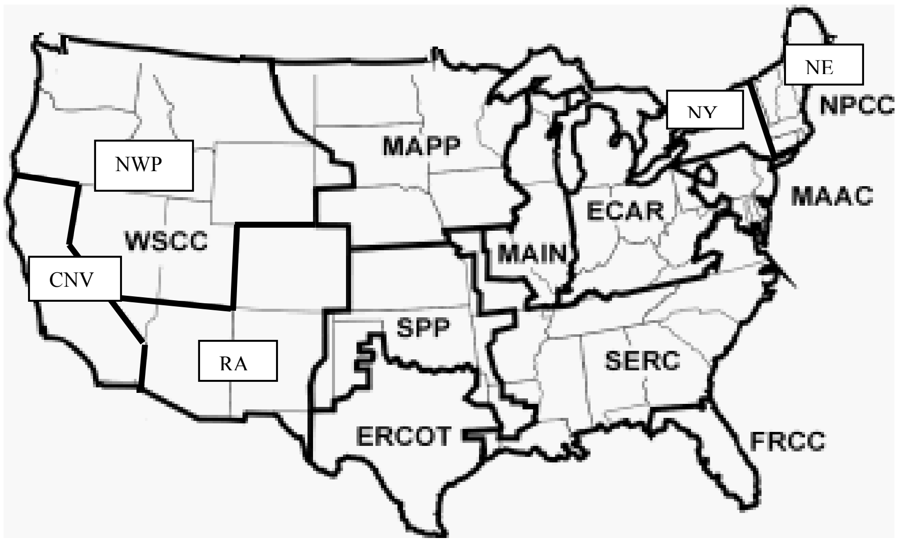


Table 3. Comparison of Regions Used by the Models			
Region	ORCED	NEMS	IPM
Northeast	NPCC	NPCC/NY	UPNY
		NPCC/NE	NENG
			LILC
Mid-Atlantic	MAAC	MAAC	MACW
			MACE
			MACS
East Central	ECAR	ECAR	MECS
			ECAO
Southeastern	SERC-STV	SERC-STV	VACA
			TVA
			SOU
Florida	FRCC	SERC/FL	FRCC
Mid-America	MAIN	MAIN	MANO
			WUMS
Mid-continent	MAPP	MAPP	MAPP
Southwest	SPP	SPP	SPPS
			SPPN
Texas	ERCOT	EROCT	ERCT
Western	WSCC	WSCC/HWP	WSCP
		WSCC/RA	WSCR
		WSCC/CNV	CNV

Projections – Projection Scenarios, Input Assumptions and Projection Results

Projection Scenarios

Projections analyzed in the study fall under four scenarios: Unlimited Resources, Renewable Portfolio Standards (RPS), Environmental Impact Standards (EIS), and Base or Reference Cases. Several options were projected for each scenario such as options for different years, i.e. 2010 and 2020, for different co-firing rates, i.e. 5%, 10% and 15%, or for different standards, i.e. Low and High Carbon, 10% or 20% RPS. All biomass values are reported in English dry tons.

The Unlimited Resources scenario is not a policy option. These projections were made to compare and analyze differences in the three models' projections under the same input assumptions. They were also used to project the total market potential and the price and the quantity of available resources needed to meet the market potential for selected price categories, for each model. Projections were made by all three models, assuming Unlimited Resources, for prices of $20, $30, or $40/ton, and either with 5% or 15% co-firing. In addition, OnLocation projected market penetration assuming Unlimited Resources at $20/ton with a $15 credit. ICF projected an option of Unlimited Resources at $20/ton with 15% co-firing and the addition of capital cost, fixed operation and maintenance cost (FO&M), and efficiency losses.

Renewable Portfolio Standards (RPS) is a policy analyzed, in 2002, by EIA in response to a request by Congress. The policy, if enacted, would require utilities to have a portion of their electric generation from renewable energy. Three options were projected by EIA, a 10% RPS, a 20% RPS, and a Reference Case. All options assumed a maximum of 5% co-firing. Projections were made for the years 2010 and 2020.

Environmental Impact Standards ORNL, in 2002, completed the Southeast Study. Projections were made for three options, a Low Carbon, a High Carbon, and a Base Case.

The Base Case assumes zero NOx, zero Carbon credit, and \$142/ton SO_x Credit. The Low Carbon assumes \$2,347/ton NO_x credit, \$70/ton Carbon Credit, and \$142/ton SO_x Credit. The High Carbon assumes \$2,347/ton NO_x credit, \$120/ton Carbon Credit and \$142/ton SO_x Credit. Two separate projections were made for each, one assuming 2% and the other assuming 15% co-firing.

ICF projected the impact of a policy that would result in tripling the biopower markets on carbon reduction, by the year 2010, assuming 10% co-firing. A Reference Case was also projected under the study. Except for the total biomass used under the policy and the reference case options, data was unavailable. The results of the projections were unofficial and are included only in the overall projections result summary table. Since no other data was available there was no analysis or detail discussion of the projections.

<u>Base Case or Reference Case</u> The Base Case projections are projections made assuming the continuation of existing conditions and trends with no new energy policies or incentives. They are used to compare the projections of market penetration of the proposed scenario with market penetration projections under existing conditions with the same input assumptions.

Unlimited Resources

All three models projected market penetration with Unlimited Resources options. The models used the same input assumptions for most variables including the price of biomass, biomass availability, the percent of co-firing and the years of projection.

All models projected biopower penetration assuming that there are unlimited resources at \$20/ton. The biomass fuel price of \$20/ton represents the price at the boiler mouth. Biomass price at \$20/ton is equivalent to today's average price for a ton of coal. Projections were made for two co-firing options, one allowing a maximum of 5% and the other allowing a maximum of 15% wood co-firing. Projections were made for the years 2010 and 2020. The models assume that all the biomass resources in a region are available to all the power plants in that region. NEMS and ICF also assume that coal prices will decline over the years.

Table 6. Comparison of Input Assumption for the Unlimited Resource Scenario at $20/Dry Ton			
	ORNL	NREL	ICF
Projected oil prices decreases due to increase in increase in coal mining productivity over time	Yes	Yes	Yes
Cost of biomass fuel	$20	$20	$20
Availability of biomass fuel	No limits	No limits	No limits
Biomass co-firing rate	5% or 15%	5% or 15%	5% or 15%
Biomes emission rate			
Investment retrofit cost for biomass co-firing	None	None	None
Added Operation cost for biomass co-firing FOM	None	None	None
Added Operation cost for biomass co-firing VOM	None	None	None
Electric demand by year (source or basis) AEO 2000, AEO 2001	2000	2000	2000
EPA assumptions for regulatory analysis (included in the IPM model)	No	No	Yes
EPA assumptions for policy analysis (Included in the IPM model)	No	No	Yes
Heat content	8500 Btu/lb	8500 Btu/lb	8500 Btu/lb
Conversion rate	$1.18 per MMBtu = $20/dryton	$1.18 per MMBtu = $20 /dry ton	$1.18 per MMBbtu = $20/dry ton
Heat rate penalty for wood	None	None	None
SO2 credit value	$288.8	$250	$420
SO2 emission credit	0.0 lbs/ MMBtu	0.0 lbs/ MMBtu	0.0 lbs/ MMBtu
Nox			

Results for the Unlimited Resource Scenario Projections

The range of the projected biomass fuel consumption is 255 to 847 Trillion Btu for the 5% co-firing scenario and 778 to 2,432 Trillion Btu for the 15% co-firing scenario. All model projections triple their projections with 15% co-firing. IPM projections for 2020 are lower compared to 2010 under both 5% and 15% co-firing. Excluding the IPM projections the range is 719 to 847 Trillion Btu for the 5% co-firing and 2,170 to 2,432 Trillion Btu for 15% co-firing. The IPM 255 Trillion Btu is one third of the NEMS and ORCED projections. *A possible explanation for the lower values projected by the IPM model is that the model failed to override the supply curves input. This speculation is made because the IPM projections of 255 Trillion Btu is similar to the Reference Case projections of 248 by the NEMS model with 5% co-firing and the IPM Reference Case projection with 10% co-firing of 300 Trillion Btu for the tripling market policy scenario*.

Table 5. Comparison of Projected Biomass Consumption for the Unlimited Resourc scenario, at $20/dry ton - Trillion Btu				
	2010		**2020**	
Co-firing Rate	**5%**	**15%**	**5%**	**15%**
ORNL- Unlimited Resources $20	719	2170		
OnLocation - Unlimited Resources $20	847	2432		
ICF-Unlimited Resources $20	255	778	217	657

Unlimited Resources Projections by Region

The national calculation of power plants' co-firing capacity was similar among all models, ORCED – 52,900, NEMS – 53,100, and IPM – 53,500 Trillion Btu. Not all regions reached the 5% capacity. The projected percent of biomass consumed for the 5% co-firing, assuming Unlimited Resources at $20/ton, were; ORCED 4%, NEMS 4.7%, and IPM 1.4%. The projected percent of co-firing in each region also varies among the models. The IPM projection is limited to the regions in the Eastern part of the country. According to the OnLocation report, the reason for the regions not to reach the 5% co-firing in some regions is because new and retrofitted plants are assumed to be ineligible to co-fire. The highest proportions of such plants are in the MAAC and WSCC/CNV regions.

Table 6. Comparison of Regional Biomass Consumption Under the Unlimited Resources at $20/ton 5% Co-firing Projections -Trillion Btu									
Model	ORCED			NEMS			IPM		
$/dry ton	20			20			20		
Region	Region	Biomass Used	% Plant Capacity	Region	Biomass Used	% Plant Capacity	Region	Biomass Used	% Plant Capacity
Northeast	NPCC	1,254	5	NPCC/NY	824	5	UPNY		3.4
				NPCC/NE	647	5	NENG		4.6
							LILC		0
Mid-Atlantic	MAAC	3,176	5	MAAC	3,000	3	MACW		1.4
							MACE		3.2
							MACS		3
East Central	ECAR	11,209	4	ECAR	13,529	4	MECS		0.2
							ECAO		0.6
Southeastern	SERC-STV	12,119	5	SERC-STV	13,588	5	VACA		3.5
							TVA		2.9
							SOU		3.9
Florida	FRCC	1,764	4	SERC/FL	1,882	4	FRCC		2.3
Mid-America	MAIN	3,307	4	MAIN	5,882	5	MANO		0.5
							WUMS		0
Mid-Continent	MAPP	907	1	MAPP	2,882	3	MAPP		0
Southwest	SPP	2,679	3	SPP	4,588	4	SPPS		0.1
							SPPN		0
Texas	ERCOT	1,837	3	ERCOT	3,059	5	ERCOT		0
Western	WSCC	4,061	3	WSCC/HWP	0	0	WSCP		0
				WSCC/RA	0	0	WSCR		0
				WSCC/CNV	0	0	CNV		0.1
Total Consumed	Total	42,000	4		49,882	4.7		15,000	1.4
Co-firing Capacity		52,900	5		53,100	5		53,500	5

Results of OnLocation Unlimited Resources Projections

OnLocation projected biomass consumed under the Unlimited Resources scenario for $20, $30 and $40/ton, assuming 5% and 15% co-firing, for the year 2010. At $20/ton, there was market penetration in all regions. At $30/ton the biomass used was only in four regions, New England, New York, Florida, and MAAC, and was limited to six percent of that at $20/ton. MAAC share was over 50% of the national total for the projected biomass used at $30/ton.

There was no market at all at $40/ton. In the 15% co-firing with Unlimited Resources at $20/ton, the biomass consumed tripled in all model projections. Since the resources are unlimited, the increase is proportionate to the increase in power plant co-firing capacity. The combined total for three regions, ECAR, SERC/STV and MAIN, is 66% of the national total, for 5% co-firing in 2010. The three regions share increases to 73% under the 15% co-firing scenario.

Table 7. Comparison of OnLocation Projected Biomass Consumption for Three Price Categories Under the Unlimited Resources Scenario, for 2010 (Trillion Btu)

Region	5 Percent Limit					15 Percent Limit				
	$20	%	$30	%	$40	$20	%	$30	%	$40
ECAR	**230**	**27%**	0	0%	0	**771**	**32%**	0	0%	0
ERCOT	52	6%	0	0%	0	156	6%	0	0%	0
MAAC	51	6%	27	52%	0	154	6%	82	53%	0
MAIN	**100**	**12%**	0	0%	0	**302**	**12%**	0	0%	0
MAPP	49	6%	0	0%	0	0	0%	0	0%	0
NPCC/NY	14	2%	5	10%	0	44	2%	16	10%	0
NPCC/NE	11	1%	11	21%	0	32	1%	32	21%	0
SERC/FL	32	4%	9	17%	0	96	4%	26	17%	0
SERC/STV	**231**	**27%**	0	0%	0	**702**	**29%**	0	0%	0
SPP	78	9%	0	0%	0	175	7%	0	0%	0
WSCC/HWP	0	0%	0	0%	0	0	0%	0	0%	0
WSCC/RA	0	0%	0	0%	0	0	0%	0	0%	0
WSCC/CNV	0	0%	0	0%	0	0	0%	0	0%	0
Total	848		52		0	2432		156		0

<u>OnLocation projected the market penetration assuming Unlimited Resources at $20/ton with $15/MWh Co-firing Credit</u>. The projection results are shown in the table below. The effect of the $15/MWh credit is equivalent to $23-$25/ton. Since for most regions, the price at twenty dollars was already competitive and reached the maximum co-firing capacity of 5%, the credit provided increased the biomass consumption only in regions where the biomass consumption was at less than the capacity at $20/ton, and required a lower biomass price to be competitive with coal.

Table 8. OnLocation Projection of Biomass Co-firing with a $15/mWh Credit with Unlimited Resources at $20/dry ton for 2010 - Trillion Btu		
	5 % Limit	5 % Limit & $15/mWh Credit
Region	$20/dry ton	$20/dry ton
ECAR	230	263
ERCOT	52	52
MAAC	51	51
MAIN	100	100
MAPP	49	81
NPCC/NY	14	14
NPCC/NE	11	11
SERC/FL	32	32
SERC-STV	231	232
SPP	78	106
WSCC/HWP	0	46
WSCC/RA	0	60
WSCC/CNV	0	16
Total	848	1,065

Results of ICF Projections for Other Options Under the Unlimited Resources Scenario

ICF projected the market penetration assuming the availability of Unlimited Resources at $30/dry ton for 5% and 15% co-firing. The IPM projection had no market penetration at $30/ton. ICF also tested an option with Unlimited Resources at $20/ton, 15% co-firing, and the addition of added power plant retrofit costs. There was no market penetration when the cost for retrofit was added.

ICF projected an option of Unlimited Resources at $20/dry ton with 15% co-firing and the added cost of operation and management (O&M) and heat loss. Projections with the added cost resulted in no market penetration. Co-firing at $1.25/million Btu ($20/dry ton) is not competitive if the cost of capital for O&M, retrofit, and heat loss is included. Based on the assumption made by ICF for the cost of O&M at the power plant, if the cost is added to the price of the biomass, the competitive price at the mouth of the boiler would be $1/million Btu.

Renewable Portfolio Standards Scenario

EIA projected the potential market for biopower assuming that utilities would be required to generate electricity with renewable resources. Two options were evaluated: one would require 10% and the other would require 20% of the utility electric generation to be from renewable resources. The projections assume 5% co-firing with no added cost for the power plant retrofit. Utilities that do not meet the 10% or 20% requirement would have to pay a penalty of 3¢/kWh, which is equal to $46-$50/ton. If the value of the penalty would be applied to the price of biomass, utilities could pay $50-$80/ ton.

The Reference Case projected biomass consumption for 2010 as 248 trillion Btu. The 2020 projections of 191 trillion Btu is a decline of 23% compared to 2010 because there are fewer power plants that can co-fire, and the price of coal is cheaper.

The projections for the 10% RPS for 2010, of 435 trillion Btu, are higher by 75% over the Reference Case and for 2020, of 1,182 trillion Btu, are four and a half times the reference case and over three and a half times the 10% RPS for 2010. The biomass consumption for the 20% RPS for 2010 was 1,162 trillion Btu. The highest market penetration of 1,492 trillion Btu, projected for the 20% RPS for the year 2020, is eight times the market penetration of the reference case for 2020.

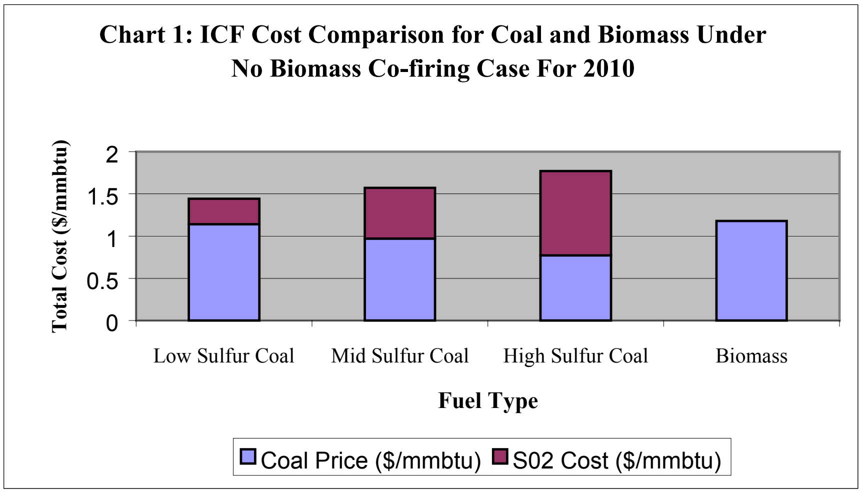
The regions with the highest market penetration for both 10% and 20% RPS are ECAR and SERC/STV. Under the Reference Case, there are five regions with penetration of over 10% of the national total, including ECAR, SERC/STV, New England, MAAC and WSCC/CNV.

Table 9. EIA Projected Biomass Consumption for 10% and 20% RPS for 2010 and 202(
Trillion Btu

Region		Reference Case		10% RPS Case		20% RPS Case	
		2010	2020	2010	2020	2010	2020
1	ECAR	40	13	69	299	241	307
2	ERCOT	7	2	25	52	52	52
3	MAAC	27	29	33	60	56	82
4	MAIN	12	5	34	104	137	190
5	MAPP	13	13	13	93	91	130
6	NPCC/NY	15	15	23	27	27	36
7	NPCC/NE	37	38	38	47	47	47
8	FL	18	16	21	41	34	55
9	STV	38	21	77	231	240	306
10	SPP	1	0	51	78	88	88
11	WSCC/NWP	7	7	7	49	31	62
12	WSCC/RA	1	0	6	62	51	62
13	WSCC/CNV	32	32	38	38	67	73
Total US		248	191	435	1182	1162	1492

Environmental Impact Standards Scenario

Data for projections made by ICF for Tripling the Market scenario were unavailable. The ICF memorandums for the Unlimited Resources projections discuss some environmental impact. The memorandums are included as Appendix 3 and Appendix 4. According to the ICF calculations, the equivalent price of biomass would vary with the quality of coal. Under the current SO_2 requirements, the equivalent price of biomass in comparison with the different grades of coal is shown in the chart below. In the case of high-sulfur coal, the competitive price of biomass increases by over 50% to $30/ dry ton. This allows biomass to be more competitive in this region with high sulfur coal.



The Southeast Study Environmental Impact Standards scenario is discussed under the Southeast Study chapter.

Resources

Two biomass supply databases, one developed by the NEMS and the other developed by ORNL, were used in the projections. The biomass supply curves provide estimates of resource availability. Quantities are estimated by resource type, by price category and measured by either English (short) dry tons or by trillion Btu. ORNL used their biomass supply estimates in their projections. All the other projections used the NEMS supply database.

NEMS developed and maintains the biomass supply curves database. The NEMS Supply Curves were developed from information provided by ORNL, Antares, and the U.S. Department of Agriculture. A recent EIA publication, written by Zia Hag, provides a thorough explanation of how the data was developed. The article, Biomass for Electricity Generation, can be viewed or downloaded from the web at http://www.eia.doe.gov/oiaf/analysispaper/index.html. The report describes how the methodology used in NEMS account for various types of biomass and explains the underlying assumptions. Forecasts of biomass growth under different scenarios are also presented.

Resource Types

ORNL biomass quantities are estimated by six categories: urban wood waste, mill residues, forest residues, agriculture residues, switchgrass, and short rotation woody crops (SRWC). NEMS database includes estimates for four resource types. In the NEMS supply curves, the mill residues and the urban wood waste are combined into a single category named urban & mill residues and the switchgrass and the SRWCs are combined into a category named energy crops.

Urban Wood Waste is waste from wood yard trimmings, construction residues, and other waste wood, including discarded consumer wood products pallets, construction waste, and demolition debris.

a. Mill residues includes residue from mill operations. Most of the mill residues are used, by industry for industrial by products and internal electric generation and heating. Only small quantities may be available for utilities electric generation.

b. Forestry residues are the cuttings that remain in forests after logging. Timber harvesting operations remove only the wood that can be used for lumber. The remaining branches are left on the ground. The portion of wood that is left on the ground could be collected and used as fuel for electric generation. Also included in the estimated forest residues is the collection of rough rotten salvable wood.

c. Agricultural residues are the straw left in the field after harvesting. A portion of the leftover stalks can be collected and used as energy fuel. Only wheat and corn residues are included in the estimates. These two represent the majority of all growing crops that could be economically collected.

d. Switchgrass is a species of grass that is grown for pasture and soil erosion protection. The grasses that currently are grown are mainly on Conservation Reserve Program (CRP) land. Farmers have extensive experience with growing switchgrass. Switchgrass however has not been used in the past as an energy crop. The current yield can be substantially improved with continuous genetic research that would make the crop more competitive as an energy source.

e. Short rotation woody crops (SRWCs) are plants that are grown for use as energy fuel. Only two plant species are included in the supply estimates, hybrid poplar and hybrid willow.

The NEMS biomass resources database will be referred to as the NEMS Supply Curve and the ORNL database as the ORNL Supply Curve. Both supply curves have been compiled and updated over the past fifteen years. The NEMS Supply Curve provides estimates for the years 1990 and 2000 through 2025. The ORNL Supply Curve provides estimates for the year 2008. Both supply curves assume that the annual estimated supply of residues remains the same over the years. The increases in availability of biomass over time are due to the increase in the availability of the energy crops. Each price category in both the NEMS and ORNL supply curves includes $10/ton for transportation from the farm gate to the power plant gate. They both also assumed that energy crops would not be grown in the three arid regions of the west.

The NEMS supply curves provide resource availability for 46 price categories ranging from 0.474 MMBtu ($8/dry ton) to 6.756 MMBtu ($115/dry ton) in 1987$ or 0.654 to 9.316 MMBtu ($11 to $158/dry ton) in 2000$. ORNL supply curve estimates are for four price categories, $20, $30, $40, and $50/dry ton. NEMS supplies are based on 1987$ and adjusted to 2000$ for the 2020 supplies. The supply prices for 2020 are adjusted by a factor of 1.38. ORNL supply prices are based on 1999$ adjusted for the year 2008. Both supply curves assume that there will not be a change in the total amount of biomass residues over time. The quantities in each residue type, forest residues, urban waste and mill residues and agriculture residues, remain the same for the years 2010 through 2020. Each price category includes $10/ton for transportation between the farm gate and the power plant gate.

NEMS Supply Curves

The total annual biomass supply estimates are; for the year 2000, 5,602 trillion Btu or 330 million dry tons, for the year 2010, 6,585 trillion Btu or 387 million dry tons, and for the year 2020, 7,102 trillion Btu or 418 million dry tons.

NEMS Supply Estimates by Resource Type

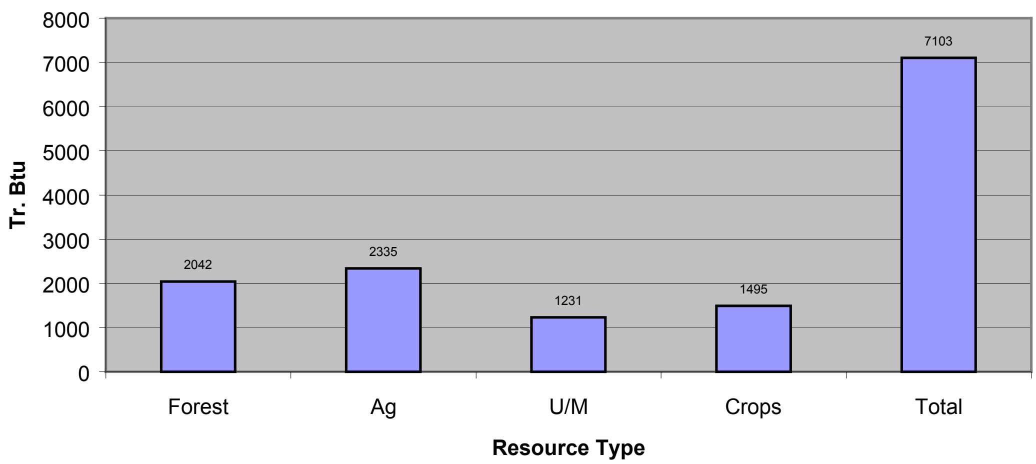
In 2010, 35% of the total resources are estimated to be in agriculture residues and 31% in forest residues. Nineteen percent of the total is in urban wood waste and mill residues and 15% are in energy crops. The combined forest and agriculture residues account for 66% of the total.

In 2020, 33% of the total resources are agriculture residues, 28%ercent are forest residues, 17% are urban wood waste and mill residues, and 22% are in energy crops. The combined forest and agriculture residues account for 61% of the total. The changes in resource availability between 2000, 2010 and 2020 are all due to the estimated increase in the availability of energy crops. The residue estimates are assumed to remain the same over the years.

Table 10. NEMS Total Biomass Estimate by Resource Type for 2010 and 2020 - Trillion

Year	Forest Res.	Urban & Mill Res.	Agricultur e Res.	Energy Crops	Total	Forest Res.	Urban & Mill Res.	Agricultur e Res.	Energy Crops
2000	2,036	1,231	2,335	0	5,602	36%	22%	42%	0%
2010	2,036	1,231	2,335	983	6,586	31%	19%	35%	15%
2020	2,036	1,231	2,335	1,501	7,103	29%	17%	33%	21%

Chart 2. NEMS Biomass estinates for the year 2020 by Resource Type



NEMS Biomass Supply Estimates by Resource Type by Price

In the NEMS supply curves for 2020, the majority of the biomass at the price of $20 and $30/dry ton is from urban and mill residues. At the price of $40/ton, biomass is predominately from agriculture residues. In the NEMS supply estimates for the year 2020, all of the biomass at the price of $20/ton, in 2000$, is from urban and mill residues. At the price of $30/ton, 93% is from urban and mill residues and 7% is from agricultural residues. At $40/ton, almost 60% is from agriculture residues and 26% is from urban and mill residues. At the $60/ton price category, 41% is from agriculture residues, 23% from forest residues and 22% from energy crops. The available resources at $20/ton, in 2000$, are small and are about 2% of the total. At the $30/ton, the available resources are 5% of the total. The available resources at the $40/ton price are 27% of the total. At the $60/ton price, the resources are about 80% of the total available biomass.

Table 11. NEMS Total Biomass Estimates by Resource Type and Price for the years 2010 and 2020

Price				2010 – Tr. Btu					Percent			
Dry Ton 1987$	MMBtu 1987$	Dry Ton 2000 $	MMBtu 2000$	Forest Residues	Urban & Mill Residues	Agricult Residues	Energy Crops	Total	Forest Residues	Urban & Mill Residues	Agricult Residues	Energy Crops
11	**0.629**	15	0.867	0	143	0	0	143	0%	100%	0%	0%
21	**1.206**	28	1.663	0	353	26	0	379	0%	93%	7%	0%
29	**1.689**	40	2.329	34	493	1,147	54	1,728	2%	29%	66%	3%
41	**2.413**	57	3.327	1,316	765	2,335	895	5,312	25%	14%	44%	17%
49	**2.896**	68	3.993	1,724	1,120	2,335	983	6,162	28%	18%	38%	16%
74	**4.343**	102	5.988	1,991	1,231	2,335	983	6,540	30%	19%	36%	15%
115	**6.756**	158	9.316	2,036	1,231	2,335	983	6,586	31%	19%	35%	15%
Price				2020 – Tr. Btu								
11	0.629	**15**	**0.867**	0	143	0	0	143	0%	100%	0%	0%
21	1.206	**28**	**1.663**	0	353	26	0	379	0%	93%	7%	0%
29	1.689	**40**	**2.329**	34	493	1,147	254	1,928	2%	26%	59%	13%
41	2.413	**57**	**3.327**	1,316	765	2,335	1,212	5,628	23%	14%	41%	22%
49	2.896	**68**	**3.993**	1,724	1,120	2,335	1,501	6,680	26%	17%	35%	22%
74	4.343	**102**	**5.988**	1,991	1,231	2,335	1,501	7,058	28%	17%	33%	21%
115	6.756	**158**	**9.316**	2,036	1,231	2,335	1,501	7,103	29%	17%	33%	21%

Table 12. NEMS Estimated Resource Availability Price Category, for 2020 - Trillion Btu			
Dry Ton 2000$	MMBtu 2000$	Total Biomass	Percent of 7103
15	0.867	143	2%
28	1.663	379	5%
40	2.329	1,928	27%
57	3.327	5,628	79%
68	3.993	6,680	94%
102	5.988	7,058	99%
158	9.316	7,103	100%

NEMS Biomass Supply Estimate by Regions and Resource Type

Biomass supplies were estimated for each State. The States' data were than compiled into the thirteen NERC regions for use as inputs in the models. When a State is split among several regions, the state total is proportionately allocated to each region.

The regional estimates for 2010 vary by the size of the region and by location. The region with the highest resources is Region 5, Mid-Continent (MAPP). The region has 22% of the national total estimated resources. Sixty-six percent of its resources are in agriculture residues. Region 1, East Central (ECAR) has the second highest resources with 16% of the national total. Forty percent of its resources are in agriculture residues and 35% in forest residues. A combined total of the forest and agricultural residues is 75% of the region's total. Region 10, Southwest (SPP), is the third highest with 14% of the national total. Energy crops represent 30% of its resources, agriculture residues 29% and forest residues 25%. The fourth highest, with 13% of the national total, is region 9, Southeast (SERC/STV). Thirty-nine percent of its resources are forest residues, 35% in urban waste and mill residues and 19% in energy crops. The Mid-America region (MAIN) has about half of the resources available in MAPP. Sixty-six percent of its resources are from agriculture residues. WSCC/NWP is the last region with significant resources. The main resources are forest residues with 64% of the total. The rest of the regions have 3% or less of the national total. However some of the regions with small quantities are also smaller in size.

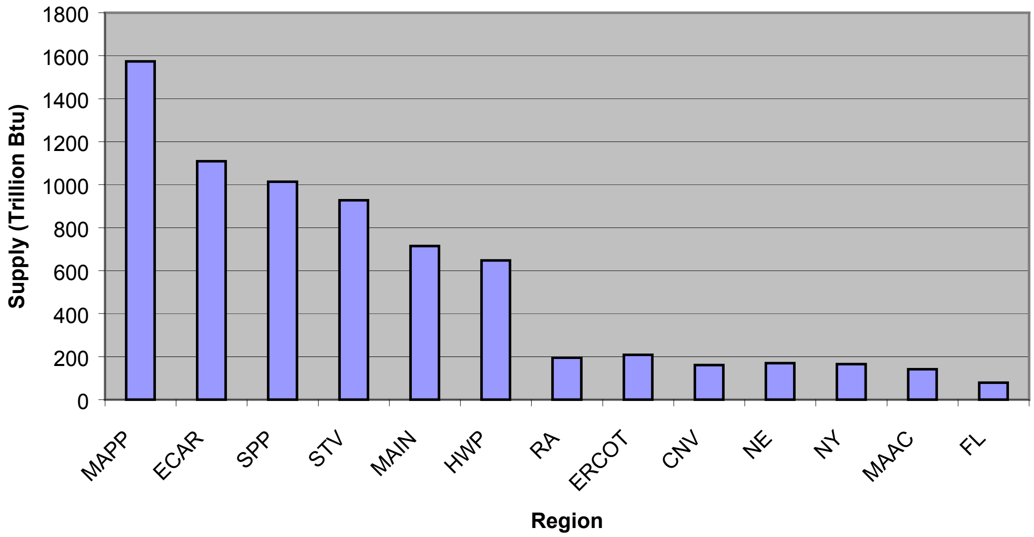
Regions with high percentage in forest residues are WSCC/NWP (64%) and WSCC/RA (57%). Regions with high percentages of agricultural residues are MAPP and MAIN. In 2020 agriculture residues represent 60% of MAPP, 62% of MAIN, 37% of ECAR, 26% of SPP, and only 7% of SERC total resources. Regions with high percentages of urban and mill residues are WSCC/CNV (58%) and SERC/FL (54%).

Except for the three western regions, where it was assumed that energy crops will not be grown, all regions have in 2020 a higher proportion of their resources in energy crops. Energy Crops represent 38% of SPP, 37% of ERCOT and 36% of NPCC/NY total biomass.

Table 13. NEMS Biomass Supply Estimates by Region for 2010 – Trillion Btu

Region	Region	Total	Forest	U/M	Crops	Ag	%Forest	%U/M	%Crops	%Ag	Region % of Nation Total
MAPP	5	1433	191	39	258	946	13%	3%	18%	66%	22%
ECAR	1	1025	363	156	98	407	35%	15%	10%	40%	16%
SPP	10	897	225	138	270	264	25%	15%	30%	29%	14%
STV	9	875	342	307	165	61	39%	35%	19%	7%	13%
MAIN	4	663	125	36	68	439	19%	5%	10%	66%	10%
WSCC/NWP	11	647	414	180	0	53	64%	28%	0%	8%	10%
WSCC/RA	12	195	105	30	6	54	54%	15%	3%	28%	3%
ERCOT	2	181	29	45	49	57	16%	25%	27%	31%	3%
WSCC/CNV	13	161	43	94	0	23	27%	58%	0%	14%	2%
NPCC/NE	7	154	81	50	23	0	53%	32%	15%	0%	2%
NPCC/NY	6	140	40	63	33	3	29%	45%	24%	2%	2%
MAAC	3	136	44	50	14	28	32%	37%	10%	21%	2%
FL	8	79	32	42	4	0	41%	53%	5%	0%	1%
Total US		6586	2034	1230	988	2335	31%	19%	15%	35%	

Chart 3. NEMS Biomass Supply Estimates by Region in 2020



NEMS Biomass Supply Estimates by Region and Price

Table 14. NEMS Biomass Supply Estimates by Region for 2020 – Trillion Btu											
	Region	Total	Forest	U/M	Crops	Ag	%Forest	%U/M	%Crops	%Ag	Region % of Nation Total
MAPP	5	1574	191	39	398	946	12%	2%	25%	60%	22%
ECAR	1	1109	363	156	183	407	33%	14%	17%	37%	16%
SPP	10	1014	225	138	387	264	22%	14%	38%	26%	14%
STV	9	927	342	307	217	61	37%	33%	23%	7%	13%
MAIN	4	712	125	36	112	439	18%	5%	16%	62%	10%
WSCC/NWP	11	647	414	180	0	53	64%	28%	0%	8%	9%
WSCC/RA	12	195	111	30	0	54	57%	15%	0%	28%	3%
ERCOT	2	209	29	45	78	57	14%	22%	37%	27%	3%
WSCC/CNV	13	161	44	94	0	23	27%	58%	0%	14%	2%
NPCC/NE	7	169	81	50	38	0	48%	30%	22%	0%	2%
NPCC/NY	6	166	41	63	59	3	25%	38%	36%	2%	2%
MAAC	3	141	44	50	19	28	31%	35%	13%	20%	2%
FL	8	79	32	43	4	0	41%	54%	5%	0%	1%
Total US	Total	7103	2042	1231	1495	2335	29%	17%	21%	33%	

The percentage in each price category, for each region, for the year 2020 is shown in the table below. In most regions the pattern is similar to the national pattern.

Table 15. NEMS Total Biomass by Regions by Price, for 2020 – Trillion Btu																	
1987$		2000$		Region													
$/ DT	$MM Btu	$/ DT	$MM Btu	1	% of Region Total	2	% of Region Total	3	% of Region Total	4	% of Region Total	5	% of Region Total	6	% of Region Total	7	% of Region Total
21	1.206	28	1.663	57	5%	15	7%	26	18%	15	2%	13	1%	25	15%	13	8%
29	1.689	40	2.329	297	27%	68	32%	36	25%	261	37%	521	33%	27	16%	17	10%
41	2.413	57	3.327	884	80%	189	90%	107	75%	645	91%	1457	93%	100	61%	98	58%
49	2.896	68	3.993	1078	97%	206	98%	136	96%	706	99%	1558	99%	144	87%	151	89%
74	4.343	102	5.988	1093	98%	210	100%	142	100%	712	100%	1571	100%	165	100%	170	100%
115	6.756	158	9.316	1110		210		142		712		1573		165		170	
				8		9		10		11		12		13		Total	% of Nation Total
21	1.206	28	1.663	23	29%	81	9%	52	5%	18	3%	10	5%	31	19%	379	5%
29	1.689	40	2.329	27	34%	197	21%	287	28%	73	11%	49	25%	69	43%	1929	27%
41	2.413	57	3.327	64	81%	742	80%	884	87%	276	43%	119	61%	104	65%	5669	80%
49	2.896	68	3.993	70	89%	904	98%	977	96%	457	71%	157	81%	135	84%	6679	94%
74	4.343	102	5.988	79	100%	926	100%	1013	100%	618	96%	184	94%	159	99%	7042	99%
115	6.756	158	9.316	79		927		1014		647		195		161		7105	

Comparison of the NEMS and ORNL Supply Curves

The table and charts below compare the resource availability between NEMS 2010 and ORNL supply curves. The comparison is by price range--$20, $30, and $40/ton, and the highest price category in each model. NEMS supplies reach the maximum between $45-$80/ton depending on the resource type. There is a difference in the estimated total national resource availability between the two databases. There are differences also among the estimated resources in each supply type. For the year 2010, ORNL total resource estimates are 30% higher than NEMS. ORNL estimates for forest residues are 63% smaller, for urban and mill residues 43% higher, for agriculture residues about 10% higher, and for energy crops about three times higher than the NEMS estimates. Significant differences also exist in the estimates by price category. The most notable difference is ORNL's estimate for agriculture residues, which is 95% smaller than NEMS.

Table 16. Comparison of Biomass Supply Between NEMS and ORNL 2010 Estimates – Trillion Btu

Price per Dry Ton	Supply Curve	Ag	For	U/M	EC	Total
20	NEMS	26	0	353	0	379
20	ORNL	0	0	405	0	404
30	NEMS	1147	34	493	54	1944
30	ORNL	54	40	1331	0	1425
40	NEMS	2335	1316	765	895	5312
40	ORNL	2301	591	1331	1124	5347
Maximum	NEMS 2010	2335	2036	1231	983	6586
Maximum	NEMS 2020	2335	2036	1231	1,501	7103
Maximum	ORNL	2561	763	2163	3197	8684

Chart 4. Comparison of Total Biomass Supply Estimates between NEMS 2010, NEMS 2020 and ORNL

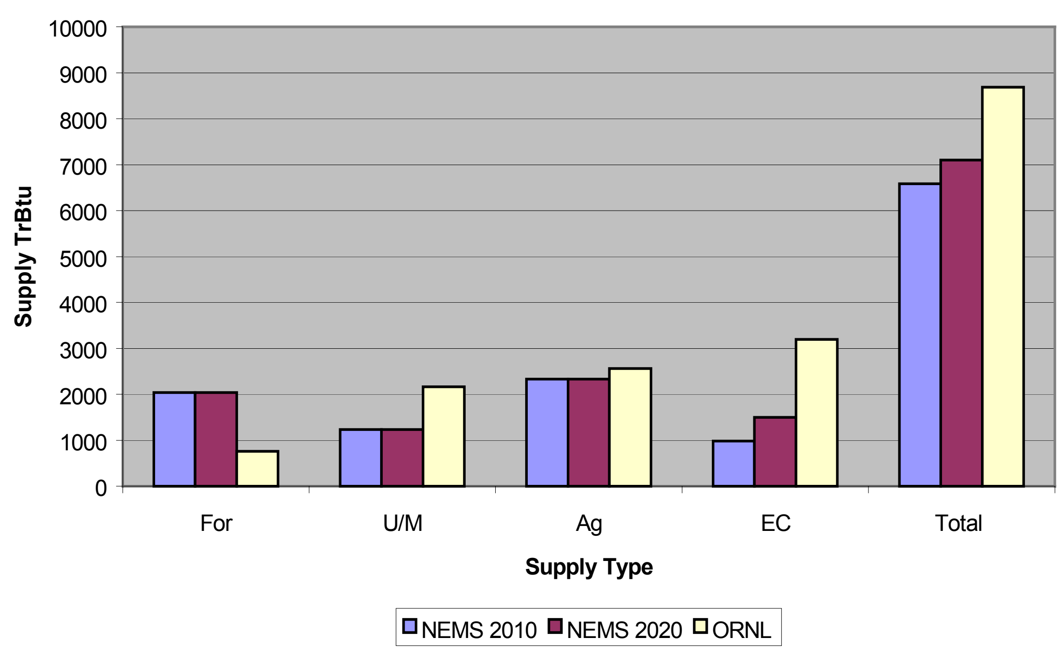


Chart 5. Comparison of Biomass Supply Between NEMS and ORNL $20 DT for 2010

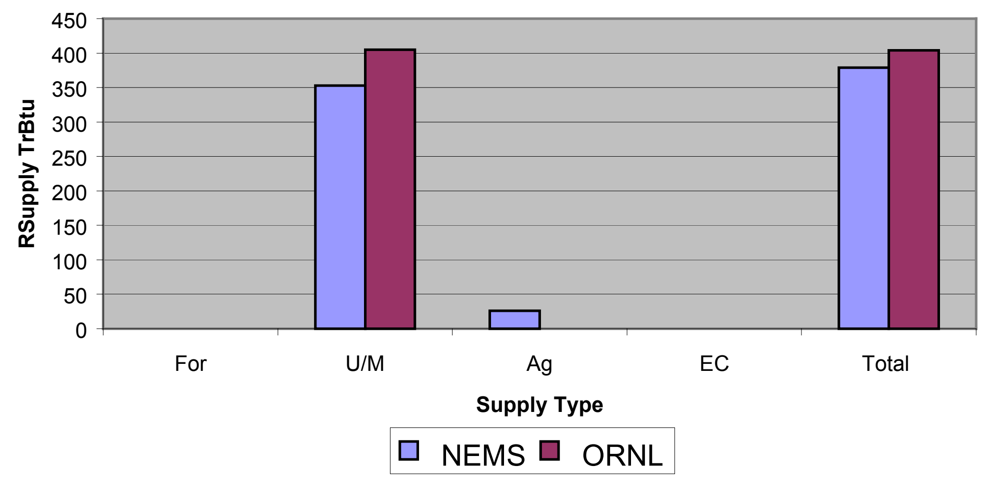


Chart 6. Comparison of Biomass Supply Curves Between NEMS and ORNL at $30 DT for 2010

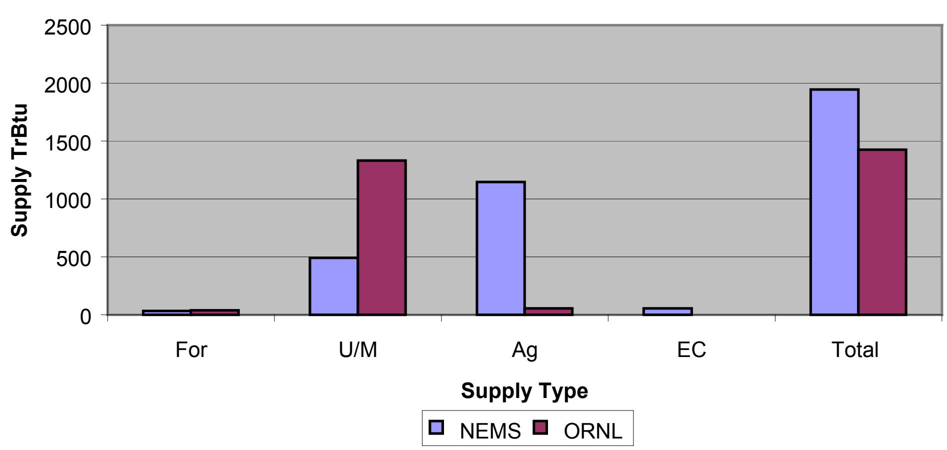
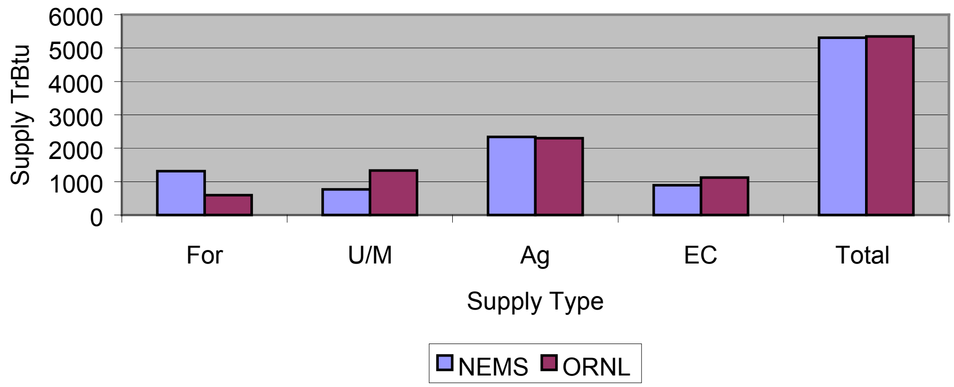


Chart 7. Comparison of Biomass Supply Between NEMS and ORNL at
$40 DT for 2010

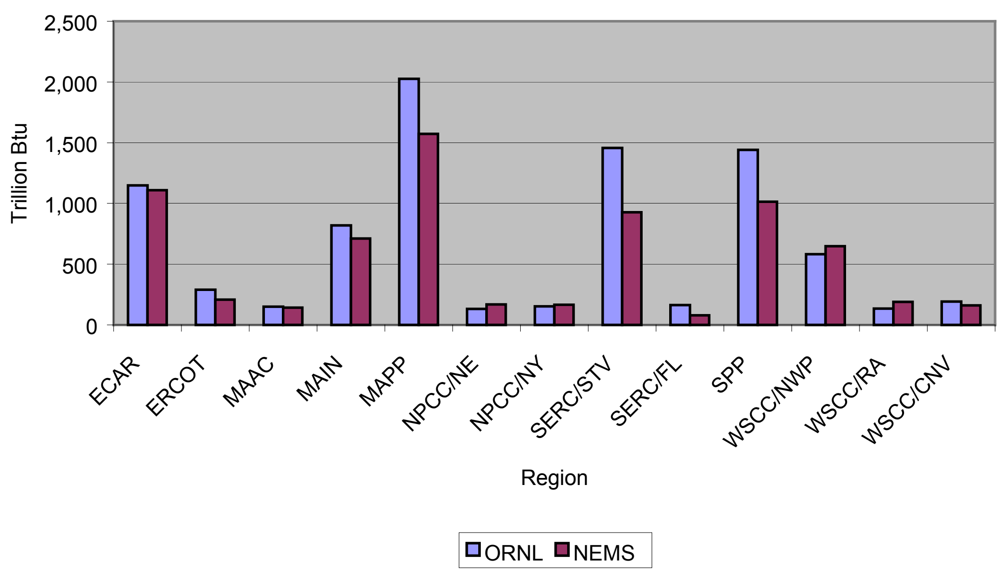


At $40/ton, the supply quantities are about the same in the two databases.

Comparison of NEMS and ORNL Supply Estimates by Region

ORNL supply estimates for MAPP, SERC/STV and SPP, the three regions with the highest quantities of resources, are about 5% higher than the NEMS estimates.

Chart 8. Comparison between ORNL and NEMS Biomass Estimates by Region



ICF NEMS Supply Curves

Two sets of the NEMS supply curves provided by ICF were evaluated. The first set has smaller overall supplies compared with the NEMS data. The second set had several values that seem to be erroneous. The total estimated resources were about 40% higher than the EIA-NEMS for 2010. The forest residue availability starts at $50/ton while the EIA-NEMS and ORNL starts at $30/dry ton. The energy crops resources are available at $20/dry ton, while IEA-NEMS and ORNL start at $40/dry ton. The second set of data seems to be completely out of character with the IEA NEMS data.

The analysis reveals that different versions of the NEMS and ORNL supply curves were used by different agencies and by the same agency for different projections.

Analysis - Comparison of Resource Availability with Projected Market Demand

The objective of the evaluation is to determine the correlation between biomass availability and the biomass demand, based on the level of market penetration under each scenario. The comparison between the scenarios is difficult. Each projection was made with different input assumptions, different subsidy levels and different assumptions of resource availability. Except for the RPS, all projections were limited to co-firing. The RPS projections included co-firing, dedicated plants, and industrial cogeneration. The market level achieved under each option was determined by the biomass price and the availability of the resource at the competitive price reached by the option. Projections of biomass consumption were made for several options for four scenarios. The results of the projections provide a general picture of the range of market potential that might be feasible if one or more of the policy scenarios were mandated. Conclusions were drawn based on the analysis, which included a comparison of the projected resources used and resource availability, an assessment of whether there were adequate resources to meet the demand at the projected biomass purchased price; at what biomass prices resource availability limited penetration; what was the main resource type used; and if there were any constraints that might limit the availability of resources at the purchased price category. The results of the analysis provided an understanding of the level of incentives that would be needed and the implication on resource policies and research to achieve an increase in the biopower market.

Comparison of resource used and total resource availability

Table 17 compares the total biomass estimated by NEMS with the projected biomass consumed under each of the major options for each scenario.

There are adequate resources to meet the projected resource demand for all the projections. The Unlimited Resources scenario assumes that the total estimated resources were available at $20/dry ton. Under the projection of Unlimited Resources, 33%-37% of the available resources would be used to meet the 2010 15% co-firing demand, and 11%-13% of the resources would be needed to meet the 5% co-firing demand. Under the 2010 Reference Cases, between 3%-5% of the available resources would be used. To meet the resources required for the 10% RPS requirements in 2010, 7% of the resources would be used, and for the 20% RPS in 2010, 18% would be used. The consumption for 2020 for the 10% RPS is 16% and for the 20% RPS is 21% of the total resources available.

Table 17. Comparison of Alternative Scenarios Projected Resource Used and Resource availab
-Trillion Btu

	2010					
Co-firing Rate	**5%**			**10-15%**		
ORNL - Unlimited Resources	719	6586	11%	2170	6586	33%
OnLocation - Unlimited Resources	847	6586	13%	2432	6586	37%
ICF-Unlimited Resources	225	6586	4%	778	6586	12%
ICF - Tripling Market - Reference				300*	6586	5%
EIA - RPS Reference	248	6586	4%			
EIA - RPS 10%	435	6586	7%			
EIA - RPS 20%	1182	6586	18%			
ICF - Tripling Market				700*	6586	11%
	2020					
ICF - Unlimited Resources	217	7100	3%	657	7100	9%
ICF - Tripling Market - Reference				300*	7100	4%
EIA - RPS Reference	191	7100	3%			
EIA - RPS 10%	1162	7100	16%			
EIA - RPS 20%	1492	7100	21%			
ICF - Tripling Market				700*	7100	10%

* 10% Co-firing

Comparison of Projected Biomass Used with Biomass Availability by Price Category

The NEMS estimated resources of 137 trillion Btu, at $15/ton in 2000$, would not be sufficient to meet any of the projections.

The NEMS estimated biomass of 379 trillion Btu, at $20/ton based on 1987$, or at $30/ton based on 2000$, would be enough to meet the demand of the Reference Cases projection. Over 60% of the estimated resources would be used. There aren't enough resources to meet the demand of any of the other projections.

The NEMS estimated biomass of 1,944 trillion Btu, at $30/dry ton based on 1987$, or at $40/dry ton based on 2000$, would be enough to satisfied the projected need of the RPS projections in 2010 and 2020, under both the 10% and the 20% RPS. Twenty-two percent of the NEMS estimated available resource would be used to meet the demand of the 2010 10% RPS. The percentage is 60% for the 2010 20% RPS and the 2020 10% RPS. Seventy-seven percent of the estimated available resources would be needed to meet the 2020 20% RPS.

The NEMS estimated available resources of 5,312 trillion Btu, at $40/ton based on 1987$, or at $60/ton based on 2000$, are enough to meet the projected demand of all scenarios.

Comparison of Supply and Projected Demand for the Unlimited Resources Scenario

The Unlimited Resources projections represent the maximum potential for co-firing under either the 5% or the 15% co-firing scenario and the projected year. There are not enough resources to meet the projected potential at the competitive price of $20/dry ton. Adequate resources are available at $30/dry ton, 1987$ or at $40/dry ton, 2000$ for 5% co-firing in 2010 in which 40% of the resources are used. There are not enough resources at this price to meet the demand for 15% co-firing. There are adequate resources to meet the demand under the $40/ton, 1987$ or $60/ton, 2000$ price category for both 5% and 15% co-firing. The projected demand is 15% of the available biomass for the 5% co-firing scenario and 43% for the 15% co-firing scenario for 2010.

Table 18. Comparison of Supply and Demand for the Unlimited Resources Projections with 5% co-firing for 2010 in Trillion Btu							
		2010-5%			2010-15%		
Price per Dry Ton	Options	Biomass Consumed	Biomass Supply	Consumed Percent of Supply	Biomass Consumed	Biomass Supply	Consumed Percent of Supply
\$20-\$30*	ORCED-Unlimited Resources	719	379	-190%	2170	379	-573%
	OnLocation - Unlimited Resources	847	379	-223%	2432	379	-642%
\$30-\$40*	ORCED- Unlimited Resources	719	1944	37%	2170	1944	-112%
	OnLocation - Unlimited Resources	847	1944	44%	2432	1944	-125%
\$40-\$60*	ORCED- Unlimited Resources	719	5312	14%	2170	5312	41%
	OnLocation - Unlimited Resources	847	5312	16%	2432	5312	46%
* First \$ assuming 1987\$ and the second \$ assuming 2000\$							

The projections for the Unlimited Resources predict high market penetration for the ECAR and SERC regions. The tables below compare the availability of resources and the quantities of biomass that would be needed to meet the projected demand in the two regions. Biomass is available to reach the level of market predicted by the model for ECAR at 5% co-firing at a price of $40/ton in 1987$ or $60/ton in 2000$. In both regions 75%-80% of the resources would be needed to meet the demand at 15% co-firing. The projected demand for the 5% co-firing is 22%-25% of the available resources.

Table 19. Comparison of Resource Availability and Projected market Unlimited Resources, Region 1 - ECAR, 2010, Trillion Btu										
1987\$	2000\$	1987\$	2000\$		5%		15%		Reference	
\$/DT	\$/DT	\$ /MMBtu	\$ /MMBtu	Supply	Demand	% of Supply	Demand	% of Supply	Demand	% of Supply
11	15	0.629	0.867	23	230	-1000%	771	-3352%	37	-161%
21	28	1.206	1.663	57	230	-404%	771	-1353%	37	65%
29	40	1.689	2.329	243	230	95%	771	-317%	37	15%
41	57	2.413	3.327	873	230	26%	771	88%	37	4%
49	68	2.896	3.993	993	230	23%	771	78%	37	4%
74	102	4.343	5.988	1025	230	22%	771	75%	37	4%
115	158	6.756	9.316	1025	230	22%	771	75%	37	4%

Table 20. Comparison of Resource Availability and Projected market Unlimited Resources, Region 9 SERC, 2010, Trillion Btu										
1987$	2000$	1987$	2000$		5%		15%		Reference	
$/DT	$/DT	$ /MMBtu	$ /MMBtu	Supply	Demand	% of Supply	Demand	% of Supply	Demand	% of Supply
11	15	0.629	0.867	22	231	-1050%	702	-3191%	47	-214%
21	28	1.206	1.663	81	231	-285%	702	-867%	47	58%
29	40	1.689	2.329	156	231	-148%	702	-450%	47	30%
41	57	2.413	3.327	691	231	33%	702	-102%	47	7%
49	68	2.896	3.993	852	231	27%	702	82%	47	6%
74	102	4.343	5.988	875	231	26%	702	80%	47	5%
115	158	6.756	9.316	875	231	26%	702	80%	47	5%

Renewable Portfolio Standards

RPS Comparison by Price

As shown in the table below, there are enough resources at the $30/ton in 1987$ or $40/ton in 2000$ to meet the projected demand for all options. However, in the year 2020, 60% of the resource be used for the 10% RPS scenario and 77% would be used for the 20% RPS scenario.

Table 21. Comparison of Projected RPS Demand with Biomass Supply by Price– Trillion Btu														
Price per Ton				2010					2020					
1987$	2000$	1987$	2000$	2010	2010-10%		2010-20%		2020	2020-10%		2020-20%		
$D/Ton	$D/Ton	MMBtu	MMBtu	Supply	Used	%	Used	%	Supply	Used	%	Used	%
11	15	0.629	0.867	143	435	-304%	1162	-813%	143	1182	-827%	1492	-1043%
21	28	1.206	1.663	379	435	-115%	1162	-307%	379	1182	-312%	1492	-394%
29	40	1.689	2.329	1944	435	22%	1162	60%	1928	1182	61%	1492	77%
41	57	2.413	3.327	5312	435	8%	1162	22%	5628	1182	21%	1492	27%
49	68	2.896	3.993	6162	435	7%	1162	19%	6680	1182	18%	1492	22%
74	102	4.343	5.988	6540	435	7%	1162	18%	7058	1182	17%	1492	21%
115	158	6.756	9.316	6586	435	7%	1162	18%	7103	1182	17%	1492	21%

RPS Comparison by Region

Table 22 compares the biomass supply with the projected biomass consumed in each region. Under the 10% RPS option for 2010, the first six regions with the highest biomass supply consumed between 1% and 9% and the six regions with the lowest biomass supplies consumed between 14% and 27%. The first six regions with the highest biomass supply consumed between 6% and 25% and the six regions with the lowest biomass supplies consumed between 17% and 53% of the regions' available resources under the 10% RPS option for 2020.

The two regions with the highest market share ECAR consumed 7% in 2010 and 27% in 2020 and SERC/STV consumed 9% in 2010 and 25 % in 2020 of the estimated biomass supply.

Table 22. Biomass Consumption by Region for RPS 10% - Trillion Btu

	2010				2020		
	Used	Avail	%		Used	Avail	%
MAPP	13	1433	1%		93	1574	6%
ECAR	69	1025	7%		299	1109	27%
SPP	51	897	6%		78	1014	8%
STV	77	875	9%		231	927	25%
MAIN	34	663	5%		104	712	15%
WSCC/NWP	7	647	1%		49	647	8%
WSCC/RA	6	195	3%		62	189	33%
ERCOT	25	181	14%		52	209	25%
WSCC/CNV	38	161	23%		38	160	24%
NPCC/NE	38	154	25%		47	169	28%
NPCC/NY	23	140	17%		27	165	17%
MAAC	33	136	24%		60	141	43%
FL	21	79	27%		41	78	53%
Total US	435	6586	7%		1182	7094	17%

The comparison of the availability of resources with the projected use for ECAR and SERC are shown in Tables 23 and 24. At the price category of $30/ton in 1987$ or $40/ton in 2000$, there would be enough biomass in ECAR to meet the projected demand under the

10% RPS for 2010 and 2020. However, 81% of the resources would be used in 2020. There are not enough resources to meet the demand at this price category for the projected demand for 20% RPS. There are adequate resources to meet the demand of all RPS options at the price of $40/ton in 1987$ or $60/ton in 2000$.

Table 23. Comparison of Supply with Projected RPS Demand for region 1-ECAR – Trillion Btu

Price per Ton				2010					2020				
1987$	2000$	1987$	2000$	2010	2010-10%		2010-20%		2020	2020-10%		2020-20%	
$D/Ton	$D/Ton	MMBtu	MMBtu	Supply	Used	%	Used	%	Supply	Used	%	Used	%
11	15	0.629	0.867	23	69	300%	299	1300%	23	241	1048%	307	1335%
21	28	1.206	1.663	57	69	121%	299	525%	57	241	423%	307	539%
29	40	1.689	2.329	243	69	28%	299	123%	297	241	81%	307	103%
41	57	2.413	3.327	873	69	8%	299	34%	884	241	27%	307	35%
49	68	2.896	3.993	993	69	7%	299	30%	1078	241	22%	307	28%
74	102	4.343	5.988	1025	69	7%	299	29%	1110	241	22%	307	28%
115	158	6.756	9.316	1025	69	7%	299	29%	1110	241	22%	307	28%

The pattern is similar for the SERC/STV region. The projected biomass used for the 10% RPS for 2010 of 77 trillion BTU is 49% of the available supply at the price category of $30/ton in 1987$. There are not enough resources at this price, to meet any of the demand of the other options. There is adequate supply to meet all projected option resource demands at the $40/ton in 1987$.

Table 24. Comparison of Supply with Projected RPS Demand for Region 9 SERC/STV – Trillion Btu

Price per Ton				2010					2020				
1987$	2000$	1987$	2000$	2010	2010-10%		2010-20%		2020	2020-10%		2020-20%	
$D/Ton	$D/Ton	MMBtu	MMBtu	Supply	Used	%	Used	%	Supply	Used	%	Used	%
11	15	0.629	0.867	22	77	-350%	231	-1050%	22	240	-1091%	306	-1391%
21	28	1.206	1.663	81	77	95%	231	-285%	81	240	-296%	306	-378%
29	40	1.689	2.329	156	77	49%	231	-148%	197	240	-122%	306	-155%
41	57	2.413	3.327	691	77	11%	231	33%	742	240	32%	306	41%
49	68	2.896	3.993	852	77	9%	231	27%	904	240	27%	306	34%
74	102	4.343	5.988	874	77	9%	231	26%	926	240	26%	306	33%
115	158	6.756	9.316	875	77	9%	231	26%	927	240	26%	306	33%

RPS Demand and Supply Analysis by Resource Type

Most regions with large quantities of resources consist of agricultural and or forest residues. If the quantities that could be removed from the field are smaller than is assumed by the supply curves, the total resources would be smaller and the price higher. In the three regions, SERC, ECAR and MAIN, the energy crops would provide substantial amount of the resources. Energy crops may need to provide a larger amount of resources if the available quantities of agriculture and forest residues are smaller in these regions. Tables 25, 26, and 27 compare the projected demand with energy crops supply for the total national projections and for the ECAR and SERC/STV regions.

The minimum price to meet the demand only with Energy Crops is at $40/ton price category. At this price, resources are adequate only for the projected 2010 10% RPS scenario. The energy crops quantities are enough to supply the national demand for the 10% RPS at the price of $50/ton in 1987$. Forty-four percent of the resources would be used in 2010 and 79% in 2020.

Table 25. Comparison of Supply with Projected RPS Demand - Energy Crops – Trillion Btu

Price per Ton				2010					2020				
1987$	2000$	1987$	2000$	2010	2010-10%		2010-20%		2020	2020-10%		2020-20%	
$D/Ton	$D/Ton	MMBtu	MMBtu	Supply	Used	%	Used	%	Supply	Used	%	Used	%
11	15	0.629	0.867	0	435	-	1162	-	0	1182	-	1492	-
21	28	1.206	1.663	0	435	-	1162	-	0	1182	-	1492	-
29	40	1.689	2.329	54	435	-806%	1162	-2152%	254	1182	-465%	1492	-587%
41	57	2.413	3.327	895	435	49%	1162	-130%	1,212	1182	98%	1492	-123%
49	68	2.896	3.993	983	435	44%	1162	-118%	1,501	1182	79%	1492	99%
74	102	4.343	5.988	983	435	44%	1162	-118%	1,501	1182	79%	1492	99%
115	158	6.756	9.316	983	435	44%	1162	-118%	1,501	1182	79%	1492	99%

In the ECAR region, energy crops supply would be adequate to meet the projected demand for 10% RPS in 2010 where 70% of the resources be used. The energy crop supply is inadequate to meet any of the other projections.

Table 26. Comparison of Supply with Projected RPS Demand for region 1 ECAR - Energy Crops – Tri Btu

Price per Ton				2010					2020				
1987$	2000$	1987$	2000$	2010	2010-10%		2010-20%		2020	2020-10%		2020-20%	
$D/Ton	$D/Ton	MMBtu	MMBtu	Supply	Used	%	Used	%	Supply	Used	%	Used	%
11	15	0.629	0.867	0	69	-	299	-	0	241	-	307	-
21	28	1.206	1.663	0	69	-	299	-	0	241	-	307	-
29	40	1.689	2.329	0	69	-	299	-	54	241	-447%	307	-569%
41	57	2.413	3.327	94	69	73%	299	-317%	106	241	-228%	307	-290%
49	68	2.896	3.993	98	69	70%	299	-304%	183	241	-131%	307	-167%
74	102	4.343	5.988	98	69	70%	299	-304%	183	241	-131%	307	-167%
115	158	6.756	9.316	**98**	69	70%	299	-304%	183	241	-131%	307	-167%

The pattern is the same in the SERC/STV region except that the 44% of the Energy Crop supply would be used for the projected demand for the 10% RPS scenario in 2010.

Table 27. Comparison of Supply with Projected RPS Demand for region 9 SERC - Energy Crops – Trillion Btu

Price per Ton				2010					2020				
1987$	2000$	1987$	2000$	2010	2010-10%		2010-20%		2020	2020-10%		2020-20%	
$D/Ton	$D/Ton	MMBtu	MMBtu	Supply	Used	%	Used	%	Supply	Used	%	Used	%
11	15	0.629	0.867	0	77	-	231	-	0	240	-	306	-
21	28	1.206	1.663	0	77	-	231	-	0	240	-	306	-
29	40	1.689	2.329	25	77	-308%	231	-924%	66	240	-364%	306	-464%
41	57	2.413	3.327	132	77	58%	231	-175%	184	240	-130%	306	-166%
49	68	2.896	3.993	165	77	47%	231	-140%	217	240	-111%	306	-141%
74	102	4.343	5.988	165	77	47%	231	-140%	217	240	-111%	306	-141%
115	158	6.756	9.316	165	77	47%	231	-140%	217	240	-111%	306	-141%

To meet the demand for 2020, assuming the NEMS supply curves, half of the resources would need to come from residues.

Southeast Region Study

In 2002 ORNL completed a study on biopower co-firing for the Southeast region. The study, which used the ORCED model, projected biopower resource demand for a Base Case and two environmental scenarios, Low Carbon and High Carbon. Under each scenario, projections were made for two options, 2% and 15% co-firing. The study includes two important features: new biomass estimates for the Southeast region and calculations of transportation cost for each power plant, based on the location of the resources from each the plant, instead of the flat $10/ton transportation cost assumed in the national projections. ORNL is currently preparing a report describing the models used, inputs, assumptions, and results for the Southeast Study.

In this study the new supply curves and the market projections for the Southeast region are evaluated and are compared with the national resource estimates and projections. The Southeast Study covers the SERC/STV region. For convenience in the following discussion the Southeast Study would be referred to as SES.

SES Supply Estimates

The SES biomass supply estimates are organized by the same supply types as the ORNL national supply curves. Estimates were made for forest residues, agriculture residues, urban wood waste, mill residues, switchgrass, and short rotation woody crops.

Table 28. SES supply estimates for 2010, Thousand Dry Tons

	Forest Res.	Urban & Mill	Ag Res.	Energy Crop	Total
20	1,442	20,307	0	0	21,749
30	19,762	26,827	0	10,491	57,080
40	27,301	26,827	111	28,430	82,669
50	28,745	38,438	231	35,156	102,570

Comparison of Resource Estimates for the Southeast Region

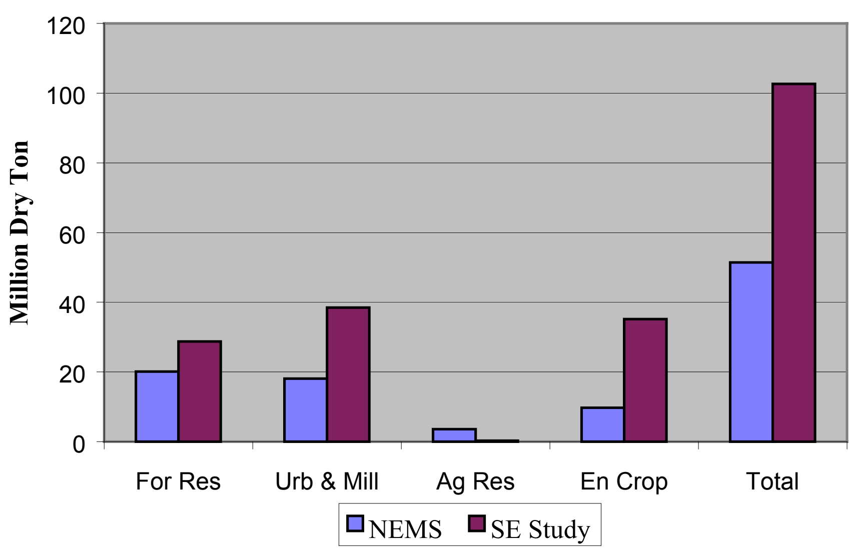
The SES supply curves are considerably different than the NEMS and the ORNL supply curves. NEMS estimates 51 million tons, ORNL 86 million tons, and the SES 103 million tons for the SERC/STV region. The SES estimate is double the NEMS estimate and twenty percent higher than ORNL estimate.

As shown in Table 29 and Chart 9, there are significant differences in the estimates among the resource types. In the SES estimates, forest residues are 43% higher, urban mill residues are 113% higher, energy crops are 262% higher, and agriculture residues are 94% lower than the NEMS estimates.

Table 29. Comparison between NENS and SES Supply Estimates for SERC in Million Dry Ton

	Forest Res.	Urban & Mill	Ag Res.	Energy Crop	Total
NEMS	20.1	18.1	3.6	9.7	51.5
SES	28.7	38.4	0.2	35.2	102.6
% Difference	43%	113%	-94%	263%	99%

Chart 9. Comparison between NENS and SES Supply Estimates for SERC

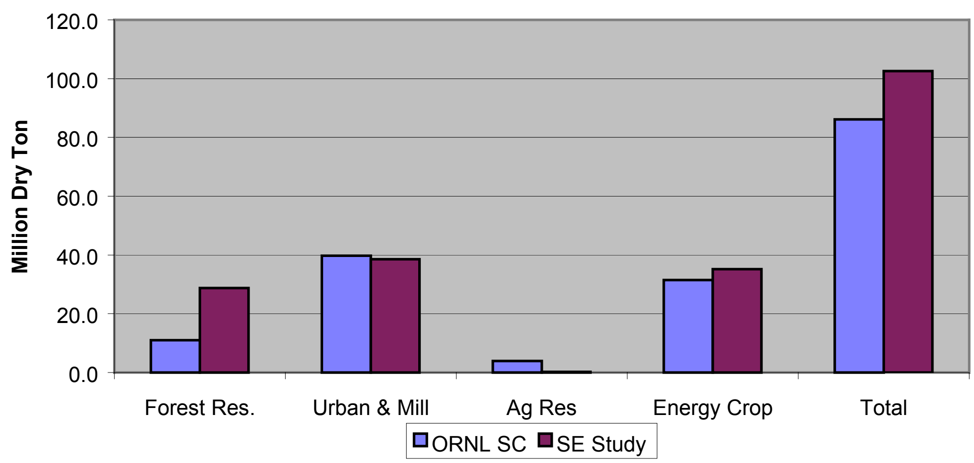


The SES estimates are also different from the ORNL supply curves for the SERC/STV region. Forest residues are three times higher, energy crops are 12% higher, urban and mill residues are about the same, and agriculture residues are 95% lower.

Table 30. Comparison between ORNL National and SES Supply Estimates for SERC Region in Million Dry Ton

	Forest Res.	Urban & Mill	Ag Res	Energy Crop	Total
ORNL	11.0	39.8	3.9	31.5	86.1
SES	28.7	38.4	0.2	35.2	102.6
% Change	162%	-3%	-95%	12%	19%

Chart 10. Comparison between ORNL Supply Curves and the SES Supply Estimates for SERC



Comparison between SES and NEMS Supply Curves by Price Categories

Each price category in the NEMS and the ORNL supply curves include $10/ton for transportation costs from the farm gate to the power plant gate. In the SES, the resource estimates are for prices at the farm gate. To compare the three supply estimates with the same transportation price assumption, $10/ton for transportation was added to the SES estimates. This was accomplished by changing the SES $12.50/ton category to $20/ton, the $20/ton category to $30/ton, the $30/ton category to $40/ton, the $40/ton category to $50/ton, and the $50/ton category to $60/ton. The change did not affect the total estimated biomass quantities. The adjustment changed the availability of resources in each price category for the SES. All supply estimates are in English dry tons.

The differences between NEMS and the SES estimates are compared in the Table 31. The only resources available in the $20/ton price category for both databases, are in urban wood waste and mill residues. The SES estimate of 906 tons are 80% lower than the NEMS estimate of 4,765 tons.

In the $30/ton price category, the total SES and NEMS resource estimates are 21,753 tons and 9,203 tons, respectively. The SES quantities are more than twice the NEMS estimates. SES forest residues are 43% and urban and mill residues 3.5 times higher than NEMS. SES has no resource,s while NEMS has 787 tons in agriculture residues and 1,492 tons in energy crops.

In the $40/ton price category, the SES estimate of 57,104 tons is 41% higher than the NEMS estimate. Urban and mill residues are 125% higher, energy crops 35% higher, and forest residues are 14% higher than NEMS estimates. The SES has no resources while NEMS estimates 3,559 tons in agriculture residues.

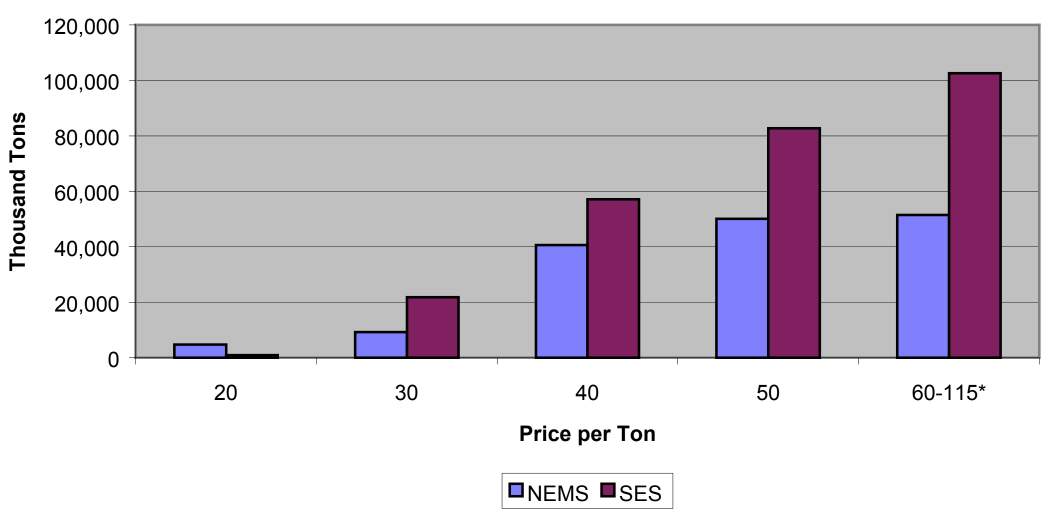
The estimate for the $50/ton and $60/ton price category follows the same differences, with higher estimates in forest residues, urban and mill residues and energy crops, and lower estimates in agriculture residues in the SES compared with the NEMS estimates.

Table 31. Comparison of NEMS and ORNL SES Supply Curves for SERC/STV by Price (Thousand Dry Tons)									
Resource Type	Forest Residues			Urban & Mill Residues			Agriculture Residues		
Price $/dry ton	NEMS	SES	% Change	NEMS	SES	% Change	NEMS	SES	% Change
20	0	0	0	4,765	906	-81%	0	0	0%
30	1,012	1,442	43%	5,912	20,307	244%	787	0	-100%
40	17,384	19,762	14%	11,903	26,827	125%	3,559	0	-100%
50	18,829	27,301	45%	18,017	26,827	49%	3,559	111	-97%
60-115*	20,098	28,745	43%	18,087	38,438	113%	3,559	231	-93%

Resource Type	Energy Crop			Total		
Price $/dry ton	NEMS	SES	% Change	NEMS	SES	% Change
20	0	0	0	4,765	906	-81%
30	1,492	0	-100%	9,203	21,749	136%
40	7,794	10,491	35%	40,639	57,080	41%
50	9,703	28,430	193%	50,109	82,699	65%
60-115*	9,703	35,156	262%	51,447	102,570	99%

* $60 for SES and $115 for NEMS

Chart 11. Comparison of Estimated Resources by Price between NEMS and SES for SERC/STV



Projected Market Penetration

The SES projected market penetration for the Base Case with 2% co-firing was 0.6 million tons or 10 trillion Btu. There was no market penetration for the Base Case with 15% co-firing. Under the Low Carbon scenario with 2% co-firing, the market penetration was 3.7 million tons or 63 Trillion Btu, a six-fold increase over the Base Case. The projection for the Low Carbon with 15% co-firing was 40 times the market penetration of the Base Case with 2% co-firing, and eight times the Low Carbon scenario with 15% co-firing. There are small differences between the market penetrations for the Low Carbon and High Carbon scenarios. The Low Carbon projection with 2% co-firing is higher than the High Carbon projection and the Low Carbon projection with 15% co-firing is lower than the High Carbon projection.

The region-averaged maximum price per ton for consumed biomass for the 2% co-firing was $20/ton for the Base Case, $49/ton for the Low Carbon scenario, and $50/ton for the High Carbon scenario. The averaged maximum price for the 15% co-firing option was $38/ton for the Low Carbon scenario and $49/ton for the High Carbon scenario. The maximum price was calculated by first averaging the maximum price of all the plants in each State and then averaging the maximum price of all the States in the region.

Table 32. SES Projected Biomass Used and Maximum Price Paid

	Base Case		Low Carbon		High Carbon	
	2%	15%	2%	15%	2%	15%
Used - Thousand Dry Ton	576	0	3,715	23,948	3,557	27,535
Used Tr. Btu	10	0	63	407	60	468
Projected Average Maximum Price per Ton for Consumed Biomass	20	0	49	38	50	49

The Resource Potential is the quantity of biomass that would be required to meet the projected demand if all the power plants that could co-fire did. The potential was not reached in two cases, the 2% co-firing Base Case where only 14% of the potential was reached and the 15% co-firing Low Carbon scenario where 83% of the potential was reached.

Resource availability at the competitive price, for several power plants, may be the reason for not reaching the potential. Even so, when comparing the regional resources with the total resources available or with the resource availability at the region's averaged price, there appear to be adequate resources to meet the demand.

Table 33. SES Resource Used Compared with Resource Potential – Thousand Dry Ton						
	Base Case		Low Carbon		High Carbon	
	2%	15%	2%	15%	2%	15%
Region Total Potential	4,194	32,222	3,715	28,906	3,557	27,562
Regional Total Used	573	0	3,715	23,948	3,557	27,535
% Used	14%	0%	100%	83%	100%	100%

In the 2% co-firing option, only 1%-4% of the available resources for the region are used; in the 15% co-firing option, 23%-27% of the available regional resources are used.

Table34. Resource Used Compared with Resource Availability – Thousand Dry Ton						
	Base Case		Low Carbon		High Carbon	
	2%	15%	2%	15%	2%	15%
Resource Available	102,627	102,627	102,627	102,627	102,627	102,627
Resource Used	573	0	3,715	23,948	3,557	27,535
% Used	1%	0%	4%	23%	3%	27%

Table 35. Comparison of SES Projected demand and Available Resources by the Averaged Maximum Price of Biomass used				
	Projection Thousand Dry Ton	Price $/dry ton	SES Resource Estimate	% Used
Base Case 2% Co-firing	576	20	906	63%
Low Carbon 15% Co-firing	23,948	40	82,669	42%
Low Carbon 2% Co-firing	3,715	50	102,570	4%
High Carbon 15% Co-firing	27,535	50	102,570	33%

Comparison with RPS Projections

The RPS projections assumed 5% co-firing, while the SES projections assumed 2% co-firing. To compare the RPS with the SES projections, an adjustment was made to the SES projections. Assuming that the market penetration would increase proportionately, the 2% co-firing projections for the SES were increased to 5% co-firing. It is important to note that even after the adjustment is made, the values are not comparable because the RPS includes dedicated power plant and industrial cogeneration.

Table 36. Comparison of NEMS and SES Projections for the Southeast Region - Dry Ton

Projections	Biomass Used	SES Adjusted to 5% Co-firing Biomass Used
SES Base Case 2% co-firing	573,143	1,432,858
RPS Base Case 5% co-firing - 2010	2,235,294	2,235,294
SES Low Carbon 2% co-firing	3,715,221	9,288,053
10% RPS, 5% co-firing - 2010	4,529,412	4,529,412
10% RPS, 5% co-firing - 2020	13,601849	13,601849

Adjusting the SES Reference Case to include a 5% co-firing rate, the SES projection is 56% lower than the NEMS Reference Case projection. The SES projection for the Low Carbon scenario, assuming 5% co-firing, is twice the projected biomass use under the 10% RPS projection for 2010, and is lower by 46% in comparison to the 10% RPS for 2020 projection.

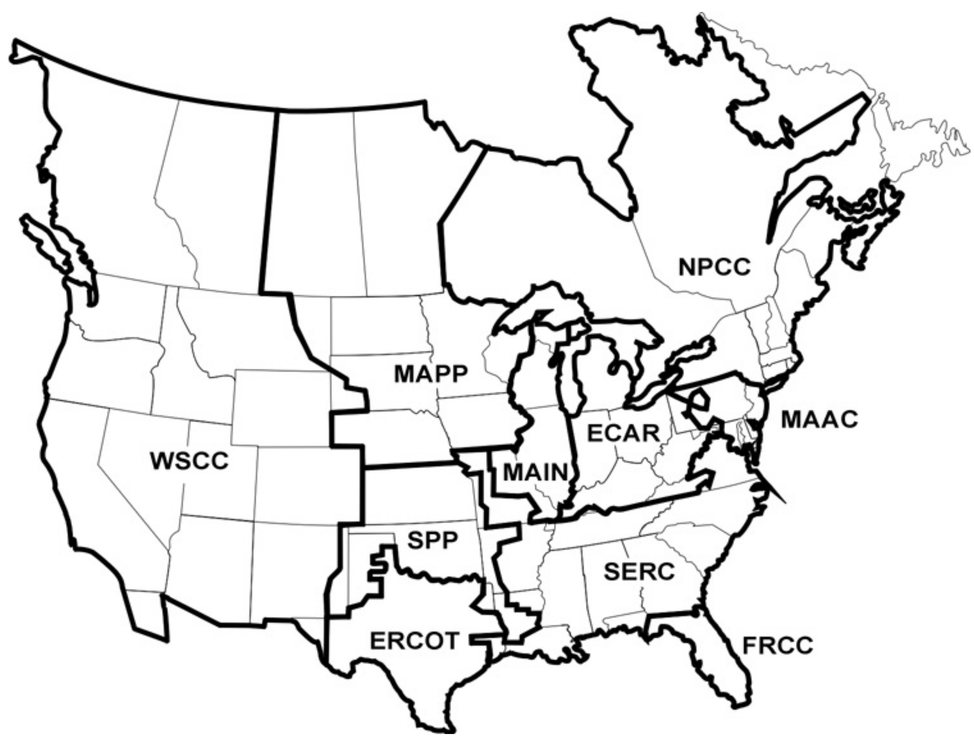
Projections with the two incentives need to be made to ascertain the biopower market potential. The two incentives combined would provide a huge market for biomass. If the SES Low Carbon projection is added to the 10% RPS projection for 2020, before the adjustment, the consumed biomass would be equal to 17 million tons, and with the SES co-firing adjustment to 5%, so it would be close to 23 million tons. Assuming the estimated resources of the SES for the region of 102 million tons, 17%-22% of the resources would be used. Thirty-four to forty-five percent of the NEMS resource estimates for the region would be used.

Appendix 1 - Biomass Co-firing Use at $20/dry ton

S. W. Hadley, 11/10/2000

Biomass co-firing has the potential to make a significant impact on the use of coal in the electric industry. To determine the potential, we used the ORCED model for each of the ten NERC regions (just the U.S. portions.) The ORCED model contained cost and operations data on all power plants in 1998. Each region was defined by the peak demands and load factors in that year, but no trading of power between regions was done. The NERC regions for the country are shown in Figure 1.

Figure 1: North American Electric Reliability Council (NERC) regions.



We allowed all coal plants to use up to 5% biomass if it was cost-effective to do so. Fuel and other costs were defined for each plant based on data submitted to FERC for that year. Some of the key parameters were:

- Unlimited quantities of \$20/dry ton biomass available. Assuming 17M Btu/dry ton, this was equal to \$1.18/MBtu.
- No capital or additional operating cost for use of biomass up to 5%.
- No heat rate penalty for biomass.
- SO_2 permit price of \$288.8/ton SO_2. No NO_x or carbon permit prices.

As a result of running the ORCED model, biomass co-firing amounts were determined as shown in Table 1.

Table 1: Biomass co-firing by region if unlimited supply at \$20/dry ton with no additional operating cost and SO_2 price of \$288.8/ton

Region	Biomass Use	% of Coal Plant Production
ECAR	11,209	4.2%
ERCOT	1,837	2.9%
FRCC	1,764	4.4%
MAAC	3,176	5.0%
MAIN	3,307	4.2%
MAPP	907	1.4%
NPCC	1,254	5.0%
SERC	12,119	4.8%
SPP	2,679	3.0%
WSCC	4,061	2.9%
Total	42,312	3.9%

Graphically these can be displayed to show the main regions where biomass co-firing could play a role. Figure 2 shows the amount of co-firing by region. The two regions where co-firing potential is most significant are the ECAR and SERC regions. These two regions, the industrial midwest and the southeast, have large amounts of coal capacity and consume 48% of the coal in the country.

In most of the regions, co-firing does not reach 5% of the total capacity because fuel costs are too low for some plants in the region. Figure 3 shows the percentage of coal-fired capacity that is displaced by biomass. Only in MAAC and NPCC, the Atlantic and New England regions, is \$20/dry ton biomass competitive in all coal plants, as modeled. Western states have enough low-cost, low-sulfur coal available that biomass does not compete at many plants.

Figure 2: Biomass co-firing by region

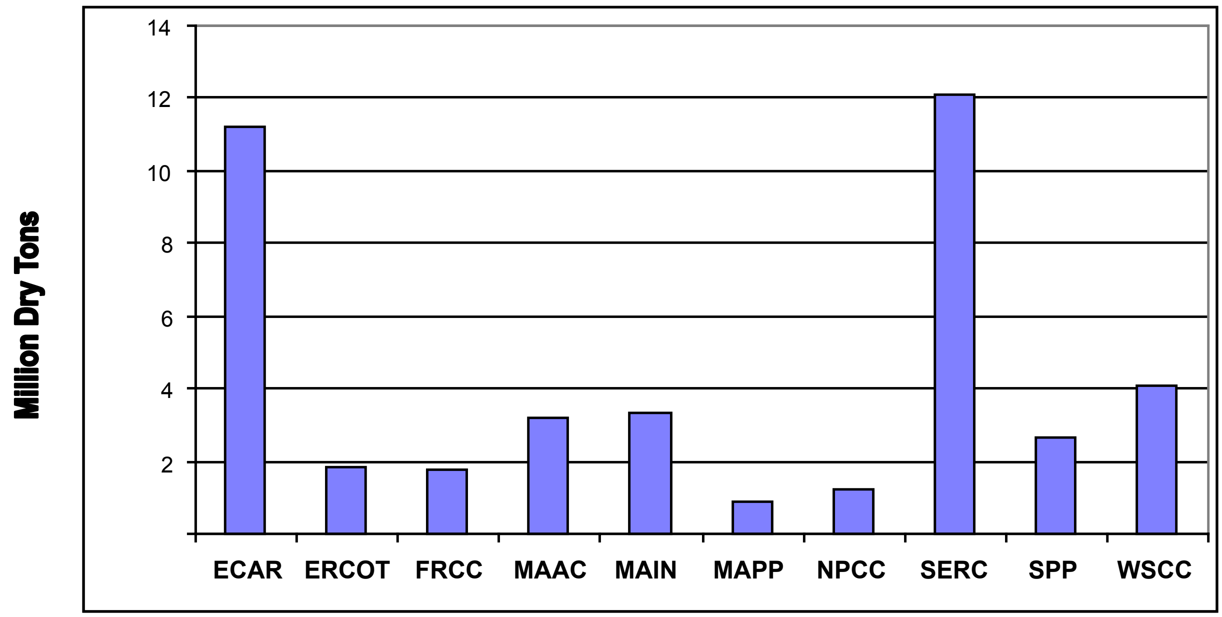
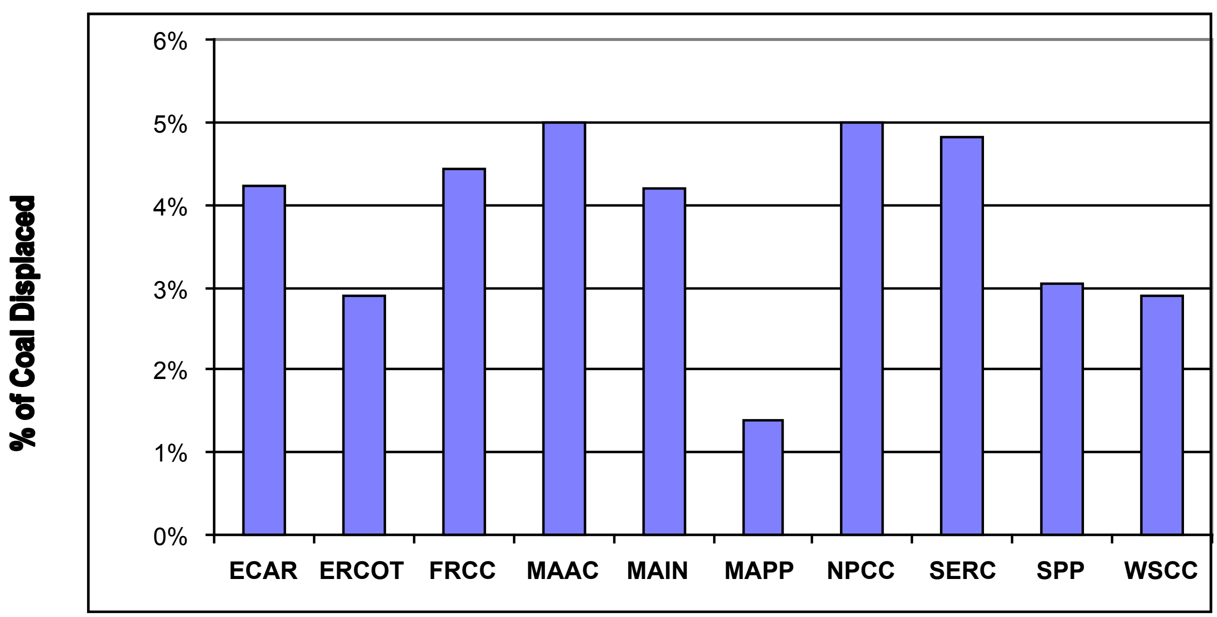


Figure 3: Percentage of coal-fired production displaced by biomass.

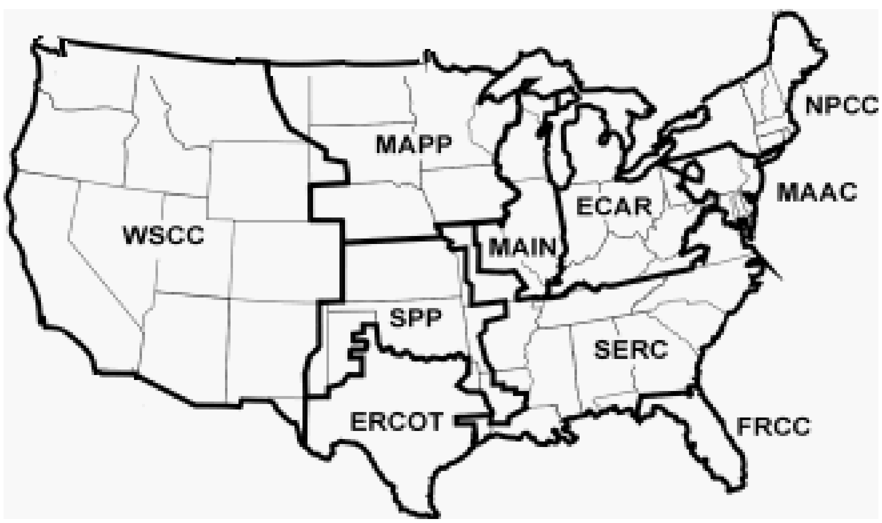


Appendix 2 - Biomass Co-firing Use at $20/dry ton with 15% Maximum

S. W. Hadley, 2/23/2001

Biomass co-firing has the potential to make a significant impact on the use of coal in the electric industry. To determine the potential, we used the ORCED model for each of the ten NERC regions (just the U.S. portions.) The ORCED model contained cost and operations data on all power plants in 1998. Each region was defined by the peak demands and load factors in that year, but no trading of power between regions was done. The NERC regions for the country are shown if Figure 1.

Figure 4: U.S. portion of North American Electric Reliability Council (NERC) regions.



In November we ran a set of cases, which allowed all coal plants to use up to 5% biomass if it was cost-effective to do so. In this set of runs we allowed plants to use up to 15% biomass. Fuel and other costs were defined for each plant based on data submitted to FERC for that year. Some of the key parameters were:

- Unlimited quantities of $20/dry ton biomass available. Assuming 17M Btu/dry ton, this was equal to $1.18/MBtu.
- No capital or additional operating cost for use of biomass up to 5%.
- No heat rate penalty for biomass.

- SO_2 permit price of \$288.8/ton SO_2. No NO_x or carbon permit prices.

As a result of running the ORCED model with the 15% limit on biomass co-firing, the amounts were determined as shown in Table 1.

Table 2: Biomass co-firing by region if unlimited supply at \$20/dry ton with no additional operating cost and SO_2 price of \$288.8/ton and plants can operate up to 15% biomass

Region	Biomass Use	% of Coal Plant Production
ECAR	33,733	12.7%
ERCOT	5,535	8.7%
FRCC	5,474	13.4%
MAAC	9,587	15.0%
MAIN	9,958	12.6%
MAPP	2,724	4.2%
NPCC	3,796	15.0%
SERC	36,566	14.4%
SPP	8,089	9.1%
WSCC	12,191	8.7%
Total	127,653	11.8%

Graphically these can be displayed to show the main regions where biomass co-firing could play a role. Figure 2 shows the amount of co-firing by region. The two regions where co-firing potential is most significant are the ECAR and SERC regions. These two regions, the industrial midwest and the southeast, have large amounts of coal capacity and consume 48% of the coal in the country.

In most of the regions, co-firing does not reach 15% of the total capacity because fuel costs are too low for some plants in the region. Figure 3 shows the percentage of coal-fired capacity that is displaced by biomass. Only in MAAC and NPCC, the Atlantic and New England regions, is \$20/dry ton biomass competitive in all coal plants, as modeled. Northern plain states have enough low-cost, low-sulfur coal available that biomass does not compete at many plants.

Figure 5: Biomass co-firing by region

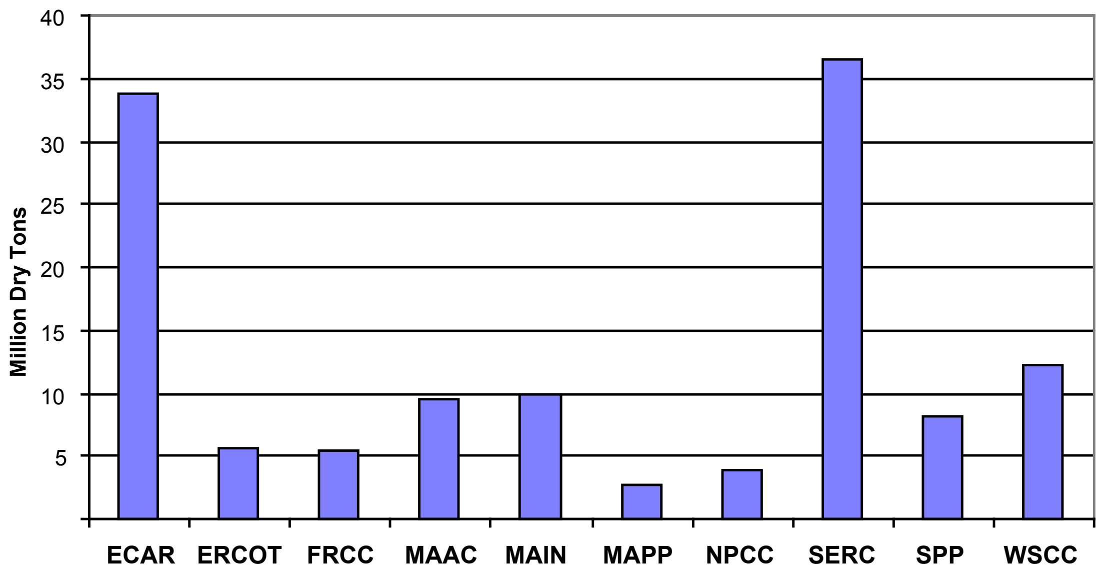
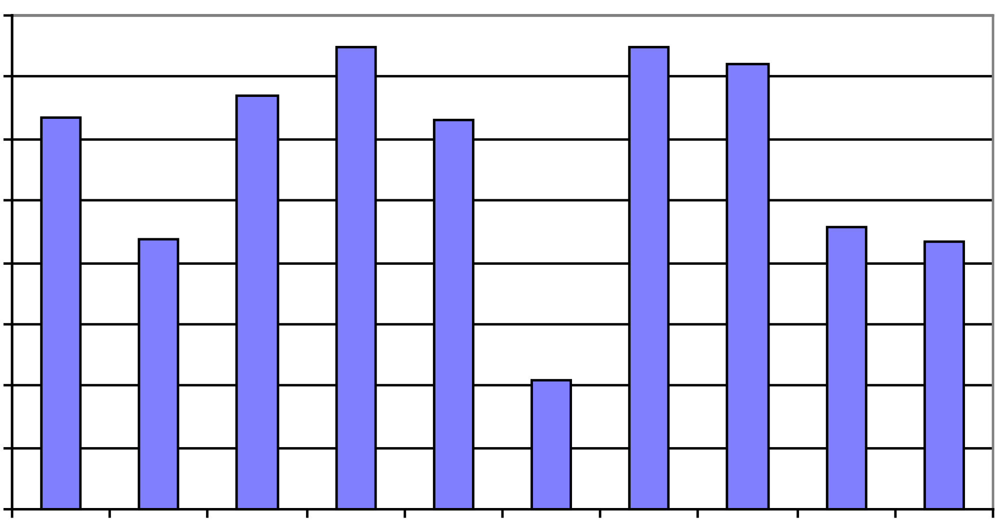


Figure 6: Percentage of coal-fired production displaced by biomass.



Appendix 3 - Potential Market Penetration of Biomass Co-firing, Interim Report

MEMORANDUM

January 31, 2001

TO:	Lynn Wright, Bob Perlack, ORNL
CC:	Jacob Kaminsky
FROM:	Juanita Haydel, Bishal Thapa, John Leahy, ICF Consulting
SUBJECT:	Potential Market Penetration of Biomass Co-firing, Interim Report Subcontract Number 400000496

This memo summarizes the results of the study on the potential market penetration of biomass co-firing. The study used ICF's Integrated Planning Model (IPM^{TM}) to evaluate the potential penetration of biomass co-firing in existing coal-fired units in two scenarios that assumed unlimited biomass supply to all coal generating units at a price of $20/dry ton. The two scenarios allowed coal plants to co-fire at five percent and fifteen percent. Both the scenarios assumed that there would be no incremental investment or operating costs incurred as a result of retrofitting to biomass co-firing.

The study analyzed the entire U.S. electric power system, capturing regional distinctions, over a time horizon between 2005 and 2020. Results from the scenarios were compared to a business as usual (BAU) base case that did not include biomass co-firing. The remainder of this memorandum describes the following:

1. Study methodology and assumptions,
2. Scenarios analyzed,
3. Results, and
4. Conclusions.

1. Study Methodology and Assumptions

This section describes the modeling tool and provides references to the assumptions used for this analysis.

The Modeling Tool

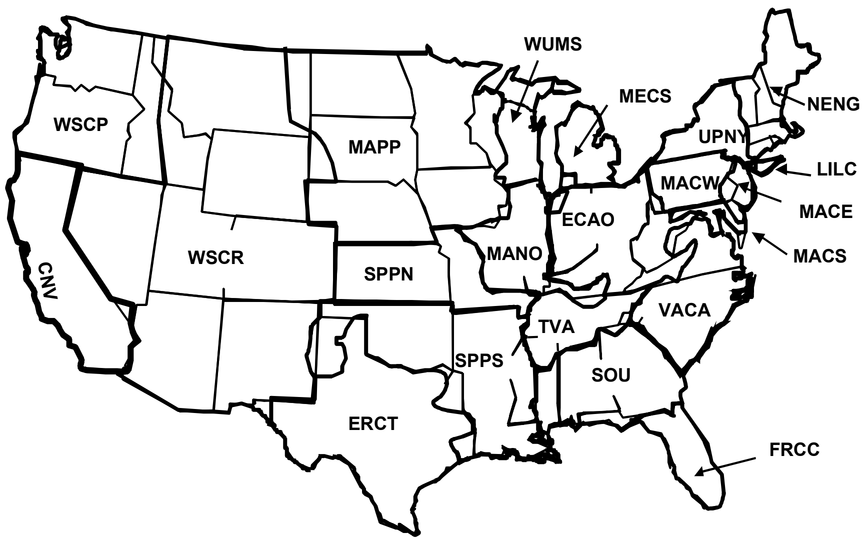
IPM^{TM} is a multi-region linear programming model that determines the least-cost operation of the electric power system to meet a specified electricity demand. IPM^{TM} decides upon the operation of the existing system and chooses new units and retrofit options based on the criteria of meeting demand at least-cost subject to constraints imposed. Constraints include unit operating constraints, emissions caps, interregional transmission limits, and regional reserve margins, among others. The model draws on a database containing detailed information on the characteristics of each utility boiler and generating unit in the U.S. For modeling purposes, these units are aggregated into *model plants* of similar characteristics.

The model has a comprehensive retrofit structure that allows modifications (environmental and other) to existing units based on economics. IPM^{TM} structurally models biomass co-firing by substituting the allowed percentage of coal fuel (on a Btu basis) with biomass fuel. In IPM^{TM}, plants select biomass co-firing only if it is economically more attractive than the other options.

IPM^{TM} projects capacity expansion and dispatch for generations into the future by selecting options that will meet electric demand at least cost to the overall power system. Ordinarily this will simply mean dispatching those existing units that have the least variable costs and building new units or retrofitting existing units in the way that will yield the lowest cost to meet growing electricity demand. If the scenario includes an environmental constraint, then the model considers retrofit, new build or fuel switching options that will not only meet electricity demand but also stay within emissions limits prescribed by the environmental constraint.

For this study, the U.S. electric system was modeled as twenty-one power markets as illustrated in Figure I below. These regions correspond in most cases to the regions and sub-regions used by the North American Electric Reliability Council (NERC). It is worth noting that the DOE NEMS model uses the 13 NERC regions. IPM regions include a finer resolution than the 13 NERC regions used in NEMS to more closely match electric wholesale markets. The results summarized in Section III below are presented at the IPM™ region level.

Figure I: IPM™ Electric Power Market Regions



Assumptions

For this screening analysis, only limited updates to modeling assumptions were performed. Assumptions about the cost and availability of biomass fuel, biomass co-firing rate, biomass emission rates and investment and operating costs for biomass co-firing retrofit were modified based on DOE's directive. In addition, assumptions on electric demand were updated with electric demand from AEO 2000. All other assumptions were based on assumptions developed by EPA for its regulatory and policy analyses[1]. These assumptions could be refined in subsequent analyses to more closely match DOE/EIA assumptions. A detailed description of the biomass related assumptions that were used in this study are contained in Table I below.

Table I: Biomass Related Assumptions

	Scenario I	Scenario II
Fuel Price (based on heat content of 8,500 btu/lb)	$1.18 per mmbtu or $20 per dry ton	$1.18 per mmbtu or $20 per dry ton
Co-firing Rate	5%	15%
Biomass Fuel Availability	Unlimited	Unlimited
Heat Rate Loss for Biomass Co-firing	No	No
Incremental Investment and Operations Costs for Biomass Co-firing	None	None
SO_2 Emission Rate for Biomass Co-firing	0.0 lbs/mmbtu	0.0 lbs/mmbtu

The study allowed all coal plants the option to retrofit, with biomass co-firing in isolation or in combination with other environmental retrofit options (i.e. Scrubbers, SCR and/or SNCR). The biomass co-firing rate is the only difference between the two scenarios listed in Table I above. The fuel price of $20 per dry ton represents the boiler mouth price.

The study analyzed the years 2005, 2010, 2020 and 2026. Results for 2010 and 2020 have been summarized in Section III below.

2. Scenarios Analyzed

Two scenarios, based on the assumptions described above, were analyzed in this study. Only the biomass co-firing rates were different between the two scenarios: 5 percent co-firing rate was used in Scenario I and a 15 percent co-firing rate was used in Scenario II. Additionally both the scenarios included current environmental regulations as outlined in Table II below.

[1] The EPA assumptions are developed in rigorous detail and may be referred to in Analyzing Electric Power Generation Under CAAA, Office of Air and Radiation, U.S. EPA March 1998. This document is available at http://www.epa.gov/capi/ipm/update.htm.

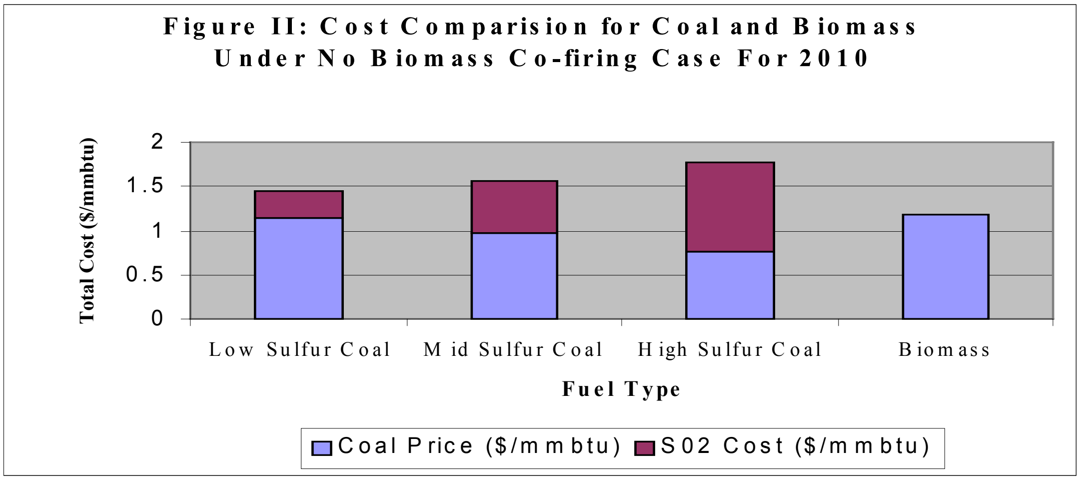
Table II. Environmental Regulations for Air Pollutants

Pollutant	Regulation
SO_2	CAAA Title IV Banking and trading Annual cap of 9470 MTons from 2005-2009 Annual cap of 8950 MTons from 2010-2030
NO_x	CAAA Title IV NO_x SIP Call for 19 states and DC Annual NO_x budget of 544 MTons for 2005-2030

3. Results

The potential for biomass co-firing depends not only on biomass fuel prices but is also critically affected by emission costs, the emission qualities of biomass co-firing and the relation to the cost of natural gas based generation. For the purposes of this study where simplifying assumptions have been made with regard to the price response of biomass fuels, biomass fuel availability, emissions from biomass fuels and biomass co-firing retrofit costs, the results represent the potential for biomass co-firing under a very limited setting. Nonetheless, the results described below capture some of the essential components of the economic tradeoffs that plants perceive when considering the choice of biomass co-firing.

In high coal cost areas, most notably in the northeast, biomass co-firing can compete against coal generation purely on the basis of fuel cost. In areas with lower coal cost, the economic advantage of biomass co-firing stems largely from environmental benefits of using biomass fuel. Since biomass co-firing can help to defray some of the emissions costs associated with SO_2 (and potentially other pollutants), coal plants may find it attractive to use biomass co-firing in order to reduce total operating costs. Figure II below compares the national average price of coal inclusive of the SO_2 emission cost against biomass fuel price under the no biomass co-firing scenario (BAU Scenario). Note that in IPM coal prices are endogenous and change as the volume of coal demanded changes.



Penetration of biomass co-firing can also be affected by the cost of generation from gas-fired units. A marginal coal plant may be capable of absorbing higher cost biomass fuel if biomass co-firing still proves cost efficient against some high cost gas based generation or some new gas based generation. In such instances, the amount of gas generation displaced hinges both on the availability of underutilized coal capacity and the price response of gas prices.

The remainder of the memorandum summarizes the results of the model runs for the 5 percent and 15 percent co-firing case.

Biomass Penetration into Coal-Fired Generation

The results of the study project biomass penetration as a percent of total coal-fired generation to range from 1.04 percent to 3.75 percent under the 5 percent and 15 percent scenarios, respectively. There is an approximately linear increase in national biomass penetration when co-firing rates are tripled from 5 percent to 15 percent. Biomass penetration decreases over time as projected coal prices decrease due to increases in coal mining productivity. Table III below summarizes the national penetration of biomass co-firing in coal-fired generation.

Table III. Biomass Penetration in Coal-Fired Generation

	2010			2020		
	Biomass Generation (Billion kWh)	Total Coal Plant Generation (Billion KWh)	Percent Biomass Co-fired Generation of Total Coal Generation	Biomass Generation (Billion kWh)	Total Coal Plant Generation (Billion kWh)	Percent Biomass Co-fired Generation of Total Coal Generation
No Co-firing Case	0	2,119	0.00%	0	2,153	0.00%
5% Co-firing	26	2,123	1.23%	22	2,155	1.04%
15% Co-firing	80	2,126	3.75%	68	2,165	3.14%

Regional Penetration of Biomass Co-Firing

As described in the section above, penetration of biomass co-firing depends both on the price of coal and the sulfur content of coal. In high coal price regions, biomass co-firing can compete against coal purely in terms of fuel prices. However, in low or mid coal price regions, biomass co-firing cannot compete against coal purely in terms of fuel price. In such regions, cost savings due to SO_2 reductions from biomass co-firing are vital to the economics of biomass co-firing. SO_2 reductions from biomass co-firing appear to be the more dominant reason for biomass penetration in regions with high sulfur low coal cost regions such as in the mid-west.

Table IV below summarizes the penetration of biomass co-firing by IPM regions for 2010 under the 5 percent and 15 percent co-firing rate scenarios.

Table IV: Regional Biomass Co-firing Penetration for 2010

IPM Region	5% Co-firing Case % of Total Coal Generation	15% Co-firing Case % of Total Coal Generation
NENG	4.6	13.9
SOU	3.9	10.7
VACA	3.5	10.6
MACE	3.2	10.2
UPNY	3.4	10.2
MACS	3.0	9.2
TVA	2.9	8.8
FRCC	2.3	6.9
MACW	1.4	4.3
ERCT	0.0	2.0
ECAO	0.6	1.7
MANO	0.5	1.6
MECS	0.2	0.6
SPPS	0.1	0.4
CNV	0.1	0.4
WUMS	0.0	0.0
MAPP	0.0	0.0
LILC	0.0	0.0
SPPN	0.0	0.0
WSCP	0.0	0.0
WSCR	0.0	0.0

The greatest penetration of biomass co-firing into coal-fired generation is in the northeast and the southeast. In the 5% co-fire case, penetration levels in these regions typically ranged from 1% to 4.5%. In the 15% co-fire case, penetration levels in these regions typically ranged from 6% to 11%. On the other hand, there was no biomass penetration in the western U.S. because biomass co-firing is not able to compete against low cost low sulfur western coal.

As was noted earlier in the section, the allowance price for SO_2 plays an important role in increasing the use of biomass co-firing. This is because plants face an implicit SO_2 emissions cost when burning coal. Biomass fuel that may not have been competitive purely in fuel price terms may prove to be attractive for co-firing because of the emissions cost savings. These emission cost savings in biomass co-firing will increase as the SO_2 allowance price increases. Emissions benefits derived from biomass co-firing may prove to be even more attractive under scenarios that include carbon or mercury reduction options. In this analysis, the SO_2 allowance price was $420/ton in 2010 under the 5 percent co-firing rate scenario and $398/ton in 2010 for 15 percent co-firing rate scenario (in 1997$). Note that the allowance prices are endogenously modeled and reflect the assumptions used for this scenario. The allowance price would change if one or more of the assumptions were modified.

Impact of Biomass Co-firing On SO_2 Reduction Options

Just as the penetration of biomass co-firing is influenced by SO_2 allowance prices, the SO_2 allowance market is also affected by the extent of biomass co-firing. The availability of biomass co-firing provides coal plants an additional option for SO_2 reduction in addition to fuel switching (from high sulfur to low sulfur) and scrubbing. As a result of biomass co-firing the compliance strategy for many coal plants will change. Table V below highlights the changes in new scrubber installation under the 5 percent and 15 percent co-firing rate scenarios.

Table V: Changes in New Scrubber Installations Under the Biomass Co-firing Scenarios

	2010	2020
Capacity (MW)		
5% Co-fire	-838	-838
15% Co-fire	-3,760	-3,760
Generation (GWh)		
5% Co-fire	-6,236	-6,236
15% Co-fire	-28,002	-28,002

Changes in new scrubber installations due to the penetration of biomass co-firing also affects the resulting allowance price in the SO_2 allowance market. Relative to the no biomass co-firing scenario, the SO_2 allowance price in 2010 drops by $30/ton under the 5 percent co-firing rate scenario and by $53/ton under the 15 percent co-firing rate scenario. The interplay between the penetration of biomass co-firing and existing or potential emissions markets or regulations is an essential component in understanding the possibilities for biomass co-firing.

Impact of Biomass Co-firing on Fuel Consumption

Biomass co-firing reduces both coal and gas consumption under the 5 percent co-firing rate and 15 percent co-firing rate scenarios. Total coal consumption declines due to the use of biomass co-firing in coal fired power generation. The availability of biomass co-firing also displaces some high cost gas based generation and that leads to the projected decline in gas consumption. Table VI highlights the changes in fuel consumption for 2010 and 2020 under the 5 percent and 15 percent co-firing rate scenarios.

Table VI: Changes in Fuel Consumption Under the Biomass Co-firing Scenarios

Fuel Consumption (TBtu)	2010	2020
Gas		
5% Co-firing	-30.5	-13.9
15% Co-firing	-45.9	-77.3
Coal		
5% Co-firing	-207.1	-196.7
15% Co-firing	-710.1	-545.3
Biomass		
5% Co-firing	254.6	216.5
15% Co-firing	778	657.2

The results noted in Table VI are sensitive to changes in gas prices. Under scenarios that include higher gas prices, such as that which exists in gas markets today, a greater share of gas consumption would be displaced by biomass co-firing. In other words, the selection of biomass co-firing also depends on gas prices and the extent to which coal based generation with biomass co-firing can provide cheaper sources for electric generation.

Impact of Biomass Co-firing on Emissions

The selection of biomass co-firing and the resulting changes in generation, capacity and fuel mix of the power system leads to changes in emissions. Table VII summarizes the national change in SO_2 and NO_x emissions for 2010 and 2020 under the 5 percent and 15 percent co-firing rate scenarios.

Table VII: Changes in Emissions Under Scenarios With Biomass Co-firing

	SO2 (MTons) 2010	% Change from Base	SO2 (MTons) 2020	% Change from Base	NOX (MTons) 2010	% Change from Base	NOX (MTons) 2020	% Change from Base
5% Co-firing	-61	-0.64%	0	0.00%	7	0.18%	1	0.02%
15% Co-firing	-90	-0.95%	0	0.00%	10	0.23%	5	0.11%

Note that in 2020, the changes in SO_2 emissions are zero because the bank of SO_2 allowances are exhausted by then and the electric sector is held to a nationwide system emissions level of 8,950M tons.

Impacts of Biomass Co-firing on System Costs

Biomass co-firing helps to reduce not just fuel but also operating costs and capital investment. The decrease in operating costs is largely due to dispatch changes as a result of biomass co-firing. As was described in preceding the section, biomass co-firing helps to displace generation from high cost gas generation. Similarly, the decrease in capital investment in 2010 is largely the result of a small decline in new scrubber installations and a small decrease in investment of new gas units. Since biomass co-firing reduces SO_2 emissions, many coal plants that would have installed scrubbers decide instead to use biomass co-firing as part of their compliance plan. This reduces the number of new scrubber installations. Similarly, the increased generation from coal plants reduces the need for investments in gas units. Although capital cost increases in 2020, the net present value of the changes in capital investments is still negative. The reversal in the direction of capital investments between 2010 and 2020 is simply the result of inter-temporal tradeoff that the system utilizes for maximizing the benefits from biomass co-firing. Table VIII summarizes the changes in total system cost for the two biomass co-firing scenarios.

Table VIII: Changes in Total System Costs Under Biomass Co-firing Scenarios Relative to the No Biomass Co-firing Scenario

Million 1997$	2010		2020	
	5 % Co-fire	15 % Co-fire	5 % Co-fire	15 % Co-fire
VOM	-3	-24	-5	-13
FOM	-7	-30	-2	-7
Fuel	-31	-74	-12	-90
Capital	-13	-62	8	83
Total	**-54**	**-190**	**-11**	**-27**

4. Conclusions

At the price of $20 per dry ton for biomass fuel, biomass co-firing achieves a 1.2 percent penetration nationally into coal-fired power generation when co-firing rate is set at 5 percent. With the same biomass fuel price and a co-firing rate of 15 percent, biomass co-firing is able to achieve 3.8 percent penetration nationally. Penetration varies by region and regions with high coal cost or high sulfur content achieve higher penetration rates.

The analysis makes it evident that coal prices are not the only factor affecting the choice for biomass co-firing rate. The SO_2 allowance markets, cost of generation from gas-fired units, cost of new technologies and environmental regulations are also key determinants driving the penetration of biomass co-firing. The analysis also makes it clear that the penetration of biomass co-firing changes the capacity and fuel mix of the electric power sector.

The results of this analysis are sensitive to a number of key assumptions including:

- Delivered price of biomass fuel. In this study, biomass fuel price has no regional variation and was assumed to be $1.18/mmbtu for all levels of biomass demand;
- Retrofit costs for biomass co-firing. In this study, no incremental operating or capital costs are incurred for biomass co-firing;
- Coal price and natural gas prices;
- Environmental regulations; and
- Electric demand.

Appendix 4 - Results of Phase II of Study on Potential Market Penetration of Biomass Co-firing

July 19, 2001

TO: Lynn Wright, Bob Perlack, ORNL

CC: Jacob Kaminsky

FROM: Bishal Thapa, John Leahy, ICF Consulting

SUBJECT: Results of Phase II of Study on Potential Market Penetration of Biomass Co-firing Subcontract Number 400000496

This memo summarizes the results of Phase II of the study on the potential market penetration of biomass co-firing. On January 31, 2001 ICF completed Phase I of the study and a memorandum containing the results was provided by ICF to ORNL (Wright and Perlack).

Both phases of the study used ICF's Integrated Planning Model (IPM®) to evaluate the potential penetration of biomass co-firing in existing coal-fired units. Both phases of the study assumed that an unlimited supply of biomass fuel would be available to all coal-fired generating units at a price of $20/dry ton for biomass co-firing. As in the previous phase of the study, this analysis included two scenarios. Both scenarios in this analysis allowed biomass co-firing at coal-fired plants but, unlike the previous phase of the study, included explicit assumptions on capital cost and FO&M cost for biomass co-firing along with efficiency losses for biomass co-firing.

Phase I of the study showed some penetration of biomass co-firing in coal-fired generation. The Phase I analysis, which assumed biomass fuel price of $20 per dry ton with no capital cost, FO&M cost or efficiency losses for biomass co-firing retrofits, resulted in a 1.2% and 3.8% penetration nationally for the scenarios with 5% and 15% co-firing rates respectively.

In Phase II, the findings suggest that biomass co-firing will not be economically competitive against other generating technologies given the capital cost, FO&M cost, efficiency losses and biomass fuel price assumed in this analysis. Biomass co-firing fails to penetrate generation markets because the incremental cost of building and operating the biomass co-firing system more than offsets the fuel and/or emission cost savings.

This study analyzed the entire U.S. electric power system, capturing regional distinctions, over a time horizon between 2005 and 2020. The remainder of this memorandum describes the following:

5. Study methodology and assumptions,
6. Scenarios analyzed,
7. Results, and
8. Conclusions.

For the remainder of this memo, unless otherwise noted this analysis refers to Phase II of the study.

5. Study Methodology and Assumptions

Assumptions

For this analysis, DOE provided the assumptions about the biomass co-firing rate, capital cost, fixed operation and maintenance cost (FO&M), efficiency losses and biomass fuel prices. Table I below provides a summary of the biomass related assumptions used in this analysis.

Table I: Biomass Related Assumptions

	Scenario I	**Scenario II**
Fuel Price (based on heat content of 8,500 Btu/lb)	\$1.18 per mmBtu or \$20 per dry ton	\$1.18 per mmBtu or \$20 per dry ton
Co-firing Rate	5%	15%
Biomass Fuel Availability	Unlimited	Unlimited
Heat Rate Loss for Biomass Co-firing	1%	2%
Incremental Capital Cost for retrofit (\$/kW)	2.5	30

Incremental FOM Cost for retrofit ($/kW-yr)	0.35	1.5
SO_2 Emission Rate for Biomass Co-firing	0.0 lbs/mmBtu	0.0 lbs/mmBtu

Relative to Phase I of the study, this analysis includes alternative assumptions on heat rate loss, incremental capital cost and FO&M cost for biomass co-firing. The Phase I analysis assumed no incremental capital cost, FO&M cost, and no efficiency loss with biomass co-firing retrofits.

This analysis provided all coal plants the option to retrofit with biomass co-firing in isolation or in combination with other environmental retrofit options (i.e. Scrubbers, SCR and/or SNCR). The biomass fuel price of $20 per dry ton represents the boiler mouth price.

The study analyzed the years 2005, 2010 and 2020. Results for 2005, 2010 and 2020 have been summarized in Section 3 below.

6. Scenarios Analyzed

Both scenarios modeled in this analysis include the same assumptions on air regulations affecting power plants. Table II below summarizes the air regulations assumed in this analysis. Phase I of the study also included the same assumptions on air regulations.

Table II. Environmental Regulations for Air Pollutants

Pollutant	Regulation
SO2	CAAA Title IV Banking and trading Annual cap of 9470 MTons from 2005-2009 Annual cap of 8950 MTons from 2010-2030
NO_x	CAAA Title IV NO_x SIP Call for 19 states and DC Annual NO_x budget of 544 MTons for 2005-2030

7. Results

There was no significant penetration of biomass co-firing in this analysis. In Scenario I, the 5% co-firing case, only 17 MW of coal capacity was retrofitted with biomass co-firing. In Scenario II, the 15% co-firing case, there were no biomass co-firing retrofits. The 1.2 % and 3.8 % biomass co-firing penetration achieved under the 5% and 15% co-firing scenarios in Phase I of the study is entirely erased due to the incremental capital cost, FO&M cost, and heat rate penalty of biomass co-firing included in this analysis.

IPM® uses annualized capital and annual FO&M costs in making capacity projections. A capital charge rate of 10.4 % is used to annualize the capital cost. In Scenario I, the 5% co-firing case, annualized capital and FO&M costs from biomass co-firing retrofit add up to $0.61/kW/year. Under Scenario II, the 15% co-firing case, the annualized capital and FO&M costs from biomass co-firing retrofit add up to $4.62/kW/year. Assuming an 80% capacity factor, the capital cost and FO&M cost for biomass co-firing increases the cost of generation by 9cents/MWh for 5% co-firing and by 65cents/MWh for 15% co-firing. The incremental 9cents/MWh and 65cents/MWh does not include the increased cost from efficiency loss due to biomass co-firing, which would require the plant to use more fuel. Given the incremental cost of biomass co-firing and all else being equal, biomass co-firing will only be competitive if the fuel price and emissions cost savings from using biomass offset the increased cost.

Based on assumptions in this analysis, biomass co-firing fails to achieve any penetration because incremental capital cost, FO&M cost, and efficiency loss from biomass co-firing more than offset the fuel price and emission cost savings from using biomass. Even in the high coal cost regions of the country, coal plants are unable to exploit the fuel price difference between biomass and coal because the incremental capital cost, FO&M cost, and heat rate loss for biomass co-firing can not be offset.

In New England, for example, delivered coal prices in this analysis were $1.45/mmBtu in 2005, $1.32/mmBtu in 2010 and $0.99/mmBtu in 2020. Even in such a high coal cost region, fuel and emission cost savings from biomass does not offset the incremental capital and FO&M cost, and efficiency losses from biomass co-firing. Using the results of Scenario I, the 5% co-firing case, and all else remaining equal, we find that a representative coal plant in New England must be able to purchase biomass fuel at less than $0.99/mmBtu for biomass co-firing to be economical for the plant. Using the results from Scenario II, the 15% co-firing case, again all else remaining equal, we find that this same representative plant must be able to purchase biomass fuel for no more than $0.79/mmBtu for biomass co-firing to be economical at this plant. In this simple illustrative calculation, we assumed that the representative coal plant in New England had a heat rate of 10,000 Btu/kWh and an emission rate of 3 lbs/mmBtu. The $20/ton biomass fuel price is equivalent to $1.18/mmBtu.

The average national coal price in this analysis was $1.02/mmBtu in 2005, $0.93/mmBtu in 2010 and $0.76/mmBtu in 2020. Since the 5% co-firing scenarios in this analysis had only 17 MW of biomass co-firing, the two scenarios were virtually identical in results.

The absence of biomass co-firing in this analysis leads to higher cost for electric generation relative to the scenarios in Phase I of this study. The increase in total system costs is because biomass co-firing is not part of the supply mix in the analysis. For the 5% co-firing scenario, the total system cost increases by $54 million in 2010 when no biomass co-firing occurs. Similarly, under the 15% co-firing scenario the total system cost increases by $189 million in 2010 when no biomass co-firing occurs. Table III below summarizes the incremental cost of the two scenarios in this analysis relative to the corresponding scenarios in Phase I of the study.

Table III: Incremental Cost of Phase II Scenarios
(Relative to corresponding Phase I scenarios)
(in millions $1997)

Year	5% Cofiring	15% Cofiring
2005	103	258
2010	54	190
2020	10	27

Conclusions

No penetration of biomass occurs in either of the two scenarios in this analysis. This result is largely because the incremental capital cost, FO&M cost, and efficiency losses from biomass co-firing is greater than the fuel and emissions cost savings from using biomass.

Please feel free to call John Leahy at 703-934-3301 or Bishal Thapa at 703-934-3904 with any questions.